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MUNICIPAL WASTE COMBUSTORS - BACKGROUND INFORMATION FOR PROPOSED GUIDELINES FOR EXISTING FACILITIES

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Research Triangle, NC

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Major categories of existing municipal waste combustor facilities are identified. Representative model plants are identified and serve as the basis of the evaluations presented. The technical feasibility, environmental benefits, and cost impacts of various retrofit options are presented for each of the model plants.

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1.0 INTRODUCTION

1.1 BACKGROUND AND REGULATORY OBJECTIVES

Regulations for existing municipal waste combustors (MWC's) will be proposed in the form of emission guidelines under the authority of Section 111(d) of the Clean Air Act (CAA). States will be required to develop specific regulations for their existing MWC's consistent with the Federal guidelines. This rulemaking will force some facilities to retrofit combustion systems and add-on emissions control. The purpose of this document is to identify the major categories of MWC's in the population and evaluate the technical feasibility, environmental benefits, and cost impacts of various retrofit options. Representative model plants have been developed and will serve as the basis for these evaluations. Although the technical feasibility and cost impacts of applying retrofit control options are site-specific, it is expected that the model plant retrofit evaluations will address the majority of site-specific situations that will be encountered in retrofitting controls to the full MWC population.

1.2 OVERVIEW OF EXISTING MWC POPULATION

There are currently about 160 MWC's in operation. Three main types of combustors are used: mass burn, modular, and refuse-derived fuel (RDF)-fired. The first type is called "mass burn" because the waste is combusted without any pre-processing other than the removal of large noncombustible items. In a typical mass burn combustor, refuse is placed on a grate system that moves the waste through the combustor. Combustion air in excess of stoichiometric amounts is supplied both below (underfire air) and above (overfire air) the grate. Mass burn combustors are usually field-erected and range in size from 50 to 1,000 tons per day (tpd) of refuse throughput per unit. The majority of mass burn facilities have two or more combustors and many have site capacities of greater than 1,000 tpd.

The mass burn category can be further divided into waterwall and refractory-wall designs. Waterwall combustors are designed to recover energy in the form of steam. Refractory-wall combustors are used for waste volume reduction and do not recover energy. Most refractory-wall combustors were built prior to the early 1970's. Newer units are waterwall designs.

Modular combustors also burn waste without pre-processing, but they are typically shop fabricated and generally range in size from 5 to 120 tpd of refuse throughput. One of the most common types of modular combustors is the starved-air or controlled-air type, incorporating two combustion chambers. Combustion air is supplied to the primary combustion chamber at substoichiometric levels. The incomplete combustion products pass into the secondary combustion chamber where excess air is added and combustion is completed. Another type of modular combustor, functionally similar to larger, mass burn units, uses excess air in the primary chamber. No additional air is added in the secondary chamber.

The third main combustor type burns refuse derived fuel (RDF). This type of combustor burns a more refined waste which may vary from shredded waste to finely divided fuel suitable for co-firing with pulverized coal. Most systems that are designed to burn RDF use a spreader-stoker combustor. The RDF is burned in a semi-suspension mode. Feeding is accomplished using an air-swept distributor. Underfire air is normally preheated and introduced beneath the grate by a single plenum. Overfire air is injected through rows of high-pressure nozzles. Combustor sizes range from 320 to 1,400 tpd. Most RDF facilities have two or more combustors, and site capacities range up to 3,000 tpd.

In terms of numbers, modular and mass burn units account for the majority of MWC's. There are currently about 24 plants with mass burn refractory-wall combustors, and 25 plants with waterwall combustors. There are over 50 plants with modular starved-air combustors and about 10 plants with modular excess air combustors. Refuse-derived fuel combustors are used at about 17 plants, and there are 3 existing plants with rotary waterwall combustors. Since modular combustors tend to be much smaller than mass burn and RDF combustors, they account for a lower percent age of the national capacity despite their greater numbers.

The remaining MWC population is made up of small numbers of other types of MWC's. For example, rotary waterwall combustors burn waste without pre-processing but have a different design from most mass burn units. There are also a few fluidized-bed combustors (FBC's).

1.3 ORGANIZATION OF REPORT

This document is divided into two basic parts: (1) introduction (Sections 2.0 and 3.0), and (2) case studies. The introduction provides an overview on the selection and development of model plants, pollutants and emission rates, and technologies for controlling MWC air emissions. Case studies for model facilities are presented in Sections 4.0 through 10.0. Section 4.0 contains case studies for three mass burn refractory-wall combustors with different grate configurations.

Section 5.0 contains case studies for three different sized mass burn waterwall models. Section 6.0 contains case studies for both a large and small RDF-fired model. Section 7.0 contains case studies for two types of modular starved-air combustor. Section 8.0 presents a case study for a modular excess-air model. Section 9.0 presents a case study for a rotary waterwall combustor.

Section 10.0 presents summaries for model plants which were developed to represent project 111(d) facilities. These are facilities which will commence construction prior to November 1989 and will be subject to the 111(d) guidelines. Each of these model plants is generally similar to one of the existing model plants in Sections 4.0 through 9.0.

In sections where more than one model of similar type is presented, there is an introductory section which provides discussion relevant to all of the case studies in that section.

Each case study contains a description of an actual facility visited to gather information for model development, as well as a detailed description of the model itself. The remaining subsections of each case study detail the possible retrofit control options as well as the environmental and the cost impacts of implementing each option.

2.0 BACKGROUND AND METHODOLOGY

2.1 SITE SELECTION AND DEFINITION OF MODEL PLANTS

Due to the infeasibility of conducting site-specific evaluations of each of the roughly 160 existing MWC's, a model plant approach was chosen to evaluate the impacts of retrofit controls. The initial step in selecting model MWC's for study was to define key criteria for categorizing the population of existing combustors. Major categories of combustors include:

- o Mass Burn Waterwall Facilities
- o Mass Burn Refractory Facilities
- o Refuse-Derived Fuel-Fired (RDF) Facilities
- o Modular Facilities

These categories provided a logical starting point for grouping facilities based on combustion technology. However, within each of these groups there are combustion technologies with distinct design features which require further subcategorization. For example, there are modular facilities designed to operate in an excess-air mode while others have a starved-air primary chamber followed by an excess-air secondary chamber. Such design features significantly influence the technical feasibility and cost impacts of retrofit control options. Furthermore, size distributions in some categories warranted subcategorization by size.

The existing MWC population was divided into 12 categories, and a plant in each category was visited to gather information for representative model plant development. A detailed discussion of the rationale for site selection is contained in memoranda as Appendix A to this report. Table 2.1-1 identifies the sites visited and provides information on the combustor type, size, age, and air pollution control device (APCD) applied at each site.

Based on the plant inspections and information on the characteristics of MWC's in each category, model plant parameters were developed for each category. In some cases, the model plant parameters differed in some respects from the visited plant in order to better represent the category as a whole. In addition to the 12 model plants developed to represent existing MWC's, 5 model plants were developed to represent plants currently under construction which will be subject to the 111(d) emission guidelines, and due to size, combustion technology, or other factors are significantly

TABLE 2.1-1. MUNICIPAL WASTE COMBUSTORS VISITED FOR THIS STUDY

Facility	Type	No. of Units	Unit Size (tpd)	Start-Up Date	Air Pollution Control Device	Section
Refractory-Wall						
Philadelphia NW, PA	Refractory-Wall/Traveling Grate	2	375	1957	Electrostatic Precipitator	4.1
Sheboygan, WI	Refractory-Wall/Rocking Grate	2	120	1965	Water Sprays	4.2
Dayton, OH	Refractory-Wall/Rotary Kiln	3	300	1970	Electrostatic Precipitator	4.3
Mass Burn Waterwall						
Saugus, MA	Large Mass Burn Waterwall	2	750	1975	Electrostatic Precipitator	5.1
Nashville, TN	Mid-size Mass Burn Waterwall	3	2 @ 360 1 @ 400	1974 1986	Electrostatic Precipitator Electrostatic Precipitator	5.2
New Hanover County, NC	Small Mass Burn Waterwall	2	100	1984	Electrostatic Precipitator	5.3
Refuse-Derived Fuel						
Niagara, NY	Large RDF	2	1000	1981	Electrostatic Precipitator	6.1
Albany, NY	Small RDF	2	300	1981	Electrostatic Precipitator	6.2
Modular Starved-Air						
Tuscaloosa, AL	Modular Starved-Air with Transfer Rams	4	75	1981	Electrostatic Precipitator	7.1
Waxahachie, TX	Modular Starved-Air with Grates	2	25	1982	None	7.2
Modular Excess-Air						
Pittsfield, MA	Modular Excess-Air	3	120	1981	Electrified Gravel Bed	8.1
Rotary Waterwall						
Bay County, FL	Rotary Waterwall	2	250	1987	Electrostatic Precipitator	9.1

different from the model plants for existing MWC's. Table 2.1-2 lists information on all 17 model plants developed, including combustor type, number, size, and APCD. Further details on sites visited and development of the model plant parameters are contained in Sections 4.0 through 10.0 of this document.

2.2 WASTE CHARACTERIZATION AND EMISSIONS

Each case study presents information on baseline pollutant emissions, emissions reduction achievable with retrofit controls, costs of controls, and other environmental impacts including quantities of solid waste (combustor bottom ash and fly ash) generated with each control alternative. This section discusses waste characterization, MWC air emissions, and MWC residues (ash).

2.2.1 Waste Characterization

Municipal solid waste (MSW) is a highly variable mixture of paper, plastics, food, yard wastes, glass, ferrous and nonferrous metals, and many other materials. The composition of MSW received by a single MWC varies significantly from day-to-day as well as seasonally. In addition, MSW in different regions of the country and different locales within the same region exhibit significant differences. The extent of material recycling accomplished by waste disposers prior to delivery to the MWC facility also has a significant impact on waste composition.

In this study, two model waste compositions were used, one representing unprocessed waste and the other representing processed wastes referred to as refuse-derived fuel (RDF) which is MSW that has been shredded, and from which most of the noncombustibles such as ferrous metals and glass have been removed. The assumed chemical compositions of these two waste types are presented in Table 2.2-1. Unprocessed waste is burned in mass burn and modular MWC's while processed waste is burned in RDF-fired facilities.

2.2.2 Pollutants of Concern

The six air pollutants addressed in this analysis are:

1. polychlorinated dibenzo-p-dioxins and dibenzofurans (CDD/CDF)
2. carbon monoxide (CO)
3. particulate matter (PM)
4. trace metals
5. hydrogen chloride (HCl)
6. sulfur dioxide (SO_2)

TABLE 2.1-2. MODEL PLANTS FOR EXISTING AND UNDER CONSTRUCTION MWC's

Type	No. of Units	Unit Size (tpd)	Air Pollution Control Device	Section
Refractory-Wall				
Refractory-Wall/Traveling Grate	2	375	Electrostatic Precipitator	4.1
Refractory-Wall/Rocking Grate	2	120	Water Sprays	4.2
Refractory-Wall/Rotary Kiln	3	300	Electrostatic Precipitator	4.3
Mass Burn Waterwall				
Large Mass Burn Waterwall	3	750	Electrostatic Precipitator	5.1
Mid-size Mass Burn Waterwall	3	360	Electrostatic Precipitator	5.2
Small Mass Burn Waterwall	2	100	Electrostatic Precipitator	5.3
Small Mass Burn Waterwall (UC)[a]	2	100	Electrostatic Precipitator	10.2
Refuse-Derived Fuel				
Large RDF	2	1000	Electrostatic Precipitator	6.1
Small RDF	2	300	Electrostatic Precipitator	6.2
Large RDF (UC)[a]	2	1000	Electrostatic Precipitator	10.3
Small RDF (UC)[a]	2	300	Electrostatic Precipitator	10.4
Modular Starved-Air				
Modular Starved-Air with Transfer Rams	3	50	Electrostatic Precipitator	7.1
Modular Starved-Air with Grates	2	25	None	7.2
Modular Excess-Air				
Modular Excess-Air	2	100	Electrostatic Precipitator	8.1
Large Modular Excess-Air (UC)[a]	3	140	Electrostatic Precipitator	10.1
Rotary Waterwall				
Rotary Waterwall	2	250	Electrostatic Precipitator	9.1
Rotary Waterwall (UC)[a]	2	250	Electrostatic Precipitator	10.5

[a] Represents MWC's under construction (UC) by the end of 1989 which differ in size or combustion technology from model plants for existing MWC's.

TABLE 2.2-1. TYPICAL WASTE FEED COMPOSITION[1,2]

Constituent	Composition (%)	
	Unprocessed Waste	RDF
Carbon	25.6	33.8
Hydrogen	3.4	4.5
Oxygen	20.3	27.9
Sulfur	0.2	0.2
Nitrogen	0.5	0.5
Water	25.2	25.2
Chlorine	0.5	0.4
Inerts (ash)	24.3	7.5

A brief discussion of the formation mechanisms for each of these pollutants and the basis for estimating baseline emissions is provided in the following section.

CDD/CDF

Only a small portion of the existing MWC's have been tested for CDD/CDF. Furthermore, available measurements of CDD/CDF from the existing population of combustors are highly variable.

There are a number of theories concerning the formation of PCDD's and PCDF's from MSW combustion systems. The first theory involves the breakthrough of unreacted PCDD/PCDF present in the raw refuse. Although MSW samples at several facilities have identified trace quantities of CDD/CDF, there is general agreement that air emissions of CDD/CDF from MWC's are not primarily the result of these trace quantities in waste feed. A more plausible theory involves the conversion of species referred to as precursors which are of similar structure. For example, relatively simple reactions can convert chlorophenols and polychlorinated biphenyls to PCDD/PCDF's. The precursors can be in the refuse and can be produced by pyrolysis in oxygen-starved zones. A third mechanisms involves the synthesis of PCDD/PCDF from a variety of organics and a chlorine donor. A fourth mechanism involves the downstream formation of PCDD/PCDF due to the catalytic reaction of heavy organics and a chlorine donor. The limited data on this fourth mechanism suggests that maximum CDD/CDF formation occurs at temperatures of approximately 500°F to 600°F. At temperatures above 750°F the formation reactions are slowed considerably.

Carbon Monoxide

As waste burns in a fuel bed it releases CO, hydrogen (H_2), and unburned hydrocarbons. Additional air then reacts with the gases escaping from the fuel bed to convert CO and H_2 to CO_2 and H_2O. Adding too much air to the combustion zone will lower the local gas temperature and quench (retard) the oxidation reactions. If too little air is added, the probability of incomplete mixing increases, allowing greater quantities of organics to escape the furnace. Figure 2.2-1 depicts the CO concentration versus oxygen concentration relationship in a mass burn waterwall MWC. The curve

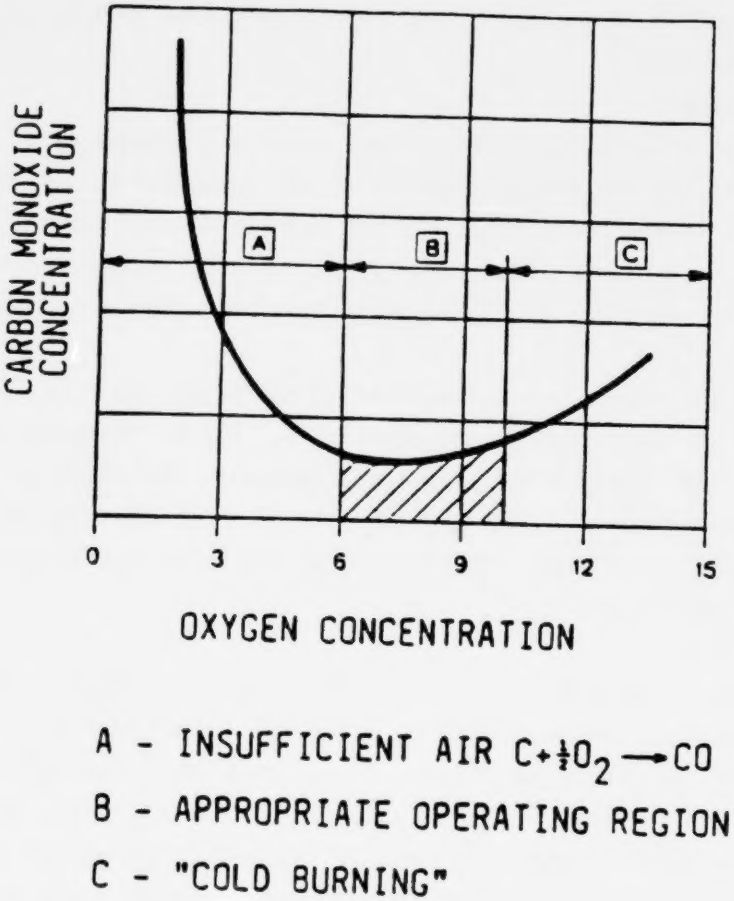

Figure 2.2-1. Relationship of CO and O_2 in a mass burn waterwall MWC.

demonstrates that CO emissions are minimized if an appropriate range of oxygen concentration is maintained.

Carbon monoxide concentrations are good indications of combustion efficiency, and are important criteria for indicating potential instabilities in the combustion process. The relationship between emissions of CDD/CDF and CO indicates that high levels of CO correspond to poor combustion conditions and hence, high CDD/CDF emissions. When CO levels are low, however, a range of CDD/CDF levels have been observed, and correlations between CO and CDD/CDF are not well defined.[5]

Particulate Matter

The amount of PM exiting the furnace of an MWC depends on the waste characteristics and the physical nature of the combustor design and operation. As stated previously, fly ash quantities vary greatly for mass burn, RDF-fired, and modular starved-air combustors. However, the level of uncontrolled PM emissions within each of these technologies are relatively consistent.

In addition to the direct impact of PM emissions, particulates contribute to air emissions in two other ways. First, trace metals comprise a portion of total particulate emissions. Secondly, the amount of particulate surface area contributes to the availability of sites for catalytic reactions involving organic compounds, thus playing a role in potential downstream formation of CDD/CDF.

Trace Metals

Trace metals present in MSW are emitted from MWC's in association with PM (e.g., arsenic, cadmium, chromium, and lead) and as a volatile gas (e.g., mercury). Control levels for PM-associated trace metals are generally similar or slightly less than those associated with total PM. Control of volatile trace metals, such a mercury, is less well defined and varies based on the operating principles of the specific control technology used.

Acid Gases

Concentrations of HCl and SO_2 in MWC flue gases are directly related to the chlorine and sulfur content in the waste. The chlorine and sulfur content varies considerably based on seasonal or local waste variations. Actual emissions of SO_2 and HCl from MWC's depend on the chemical form of sulfur and chlorine in the waste, the availability of alkali materials in combustion-generated fly ash that act as sorbents, and the type of emission control system used.

2.2.3 Baseline Emissions

Baseline emissions for CDD/CDF, CO, PM, SO_2, and HCl were established using available emissions data from facilities similar in design and/or operation to each model plant. In cases where little or no data were available for a given plant type, engineering judgement was used to establish baseline emission values. Engineering judgements were made based on an analysis of the model combustor's design and operation relative to practices in place at facilities from which emissions data are available. Potential emission-producing conditions, such as inadequate mixing, inadequate combustion control, and temperature amendable to downstream formation of CDD/CDF, were considered in the development of baseline emission estimates. For purposes of estimating baseline emission levels it is assumed that all of the chlorine and sulfur in the waste are converted to HCl and SO_2. The rationale for establishing the baseline uncontrolled emission levels of CDD/CDF, CO, and PM is discussed in a separate report.[6]

2.2.4 MWC Residues

One goal of the combustion process is to maximize the reduction of waste volume and minimize the combustible content of the remaining ash residues. Residues are classified as bottom ash, consisting of largely inert material which remains on the waste bed after combustion is completed, and fly ash, particulate matter which is carried out of the combustor with the combustion gases and deposited on heat transfer surfaces and collected by the APCD's. Bottom ash is generally discharged from the combustion chamber into a water filled quench pit. However, a few existing MWC's use dry ash removal systems. Fly ash not collected by an APCD is discharged through a stack to the atmosphere. The majority of existing MWC's transfer collected fly ash from hoppers back to the ash quench pit where it is mixed with bottom ash for co-disposal. In some cases the two ash streams remain separated and are disposed independently.

The amount of bottom ash and fly ash generated in an MWC depends on the chemical and physical composition of the waste and on combustor design and operating conditions. Refuse-derived fuel is much lower in total ash content due to waste processing activities which take place prior to combustion. However, the physical characteristics of fluff RDF and the manner in which combustion takes place (semi-suspension burning) may contribute to higher fly ash quantities. By contrast, multiple chamber starved-air modular combustors have much lower gas velocities in the primary combustion chamber, resulting in lower percentages of total ash being entrained as fly ash. A good measure of combustion efficiency is the amount of remaining carbon in the combined residues.

2.3 OVERVIEW OF TECHNOLOGIES CONSIDERED

Four retrofit control technologies are examined:

1. good combustion,
2. flue gas temperature reduction,
3. PM control, and
4. acid gas control coupled with PM control.

Good combustion practices include three elements: combustion design, combustor operation/control and verification of combustor performance. These practices promote destruction and inhibit formation of CDD/CDF. In some cases, achievement of good combustion practices requires modification of combustor design as well as combustor operating practices and verification of combustor performance.

Flue gas temperature reduction minimizes downstream formation of CDD/CDF in the flue gas. Particulate matter control technologies reduce particulate emissions, including various trace metals. Acid gas controls reduce HCl and SO_2 emissions as well as PM, CDD/CDF, and condensible particulate emissions. Performance levels for each of these four technologies are summarized in Table 2.3-1 and are discussed in Sections 2.3.1 through 2.3.4. Procedures for estimating costs for each of these technologies are presented in a companion report[6] and in Appendix B to this report.

Estimates of the amount of time required by an individual MWC for regulatory compliance (from notification of retrofit requirements through system start-up) and the amount of time an MWC is likely to be out of service during installation of equipment are presented in Table 2.3-2. Compliance and downtime requirements for actual MWC's will depend on the amount of time required to obtain needed Federal, State, and local approvals, the

TABLE 2.3-1. SUMMARY OF EMISSION CONTROL TECHNOLOGY PERFORMANCE

Technology	Control Technology Performance				Key Design and Cost Parameters
	PM	HCl	SO2	CDD/CDF	
Combustion Modifications	None	None	None	0-85%	---[a]
Temperature Control	None	None	None	See footnote a	EFGT = 450 °F[c]
ESP Rebuild	0.03-0.08 gr/dscf	None	None	See footnote a	Moderate SCA[d] EFGT = 450 °f[c]
Addition of ESP Plate Area	0.01-0.03 gr/dscf	None	None	See footnote a	Moderate SCA[d] EFGT = 450 °f
Dry Sorbent Injection/ESP	0.01-0.03 gr/dscf	50-90%	40-70%	75% or 125 ng/dscm	Sorbent/AG = 2.0-3.0[e] EFGT = 350 °F[c] Reuse ESP
Spray Drying/ESP	0.01-0.03 gr/dscf	80-90%	40-70%	75% or 125 ng/dscm	Sorbent/AG = 2.0-3.0[e] EFGT = 300 °F[c] Reuse ESP
Spray Drying/Fabric Filter	0.01 gr/dscf	90-97%	70-90%	99% or 5 ng/dscm	Sorbent/AG = 1.5-2.5[e] EFGT = 300 °F[c] New Fabric Filter

[a] CDD/CDF at ESP outlet equal to CDD/CDF at combustor outlet.

[b] See Section 2.3.1.

[c] EFGT = Exit flue gas temperature.

[d] SCA = Specific collection area.

[e] Sorbent-to-acid gas ratio.

TABLE 2.3-2. COMPLIANCE AND DOWNTIME REQUIREMENTS TO RETROFIT
EMISSION CONTROLS ON EXISTING MWC'S

	Time Requirements in Months					
	Front End Engineering	Vendor Selection[a]	Off-Site Fabrication	On-Site Construction	MWC Downtime	Total[b]
ESP - Rebuild	2 - 3	2 - 5	4 - 5	1 - 2	1 - 2	9 - 15
ESP - Add Plate Area/Field[c]	3 - 5	2 - 5	6 - 9	2 - 3[d]	0.5 - 1[d]	15 - 22[d]
Sorbent Injection with ESP Reuse	3 - 6	3 - 6	6 - 9	2 - 3[d]	0.5 - 2[d]	15 - 24[d]
Spray Dryer/Fabric Filter Retrofit	3 - 6	3 - 6	9 - 12	5 - 8[d]	0.5 - 2[d]	21 - 28[d]
Temperature Reduction	3 - 5	3 - 6	5 - 9	1 - 2[d]	0.5 - 1[d]	12 - 22[d]

[a] Includes proposal solicitation, bid review, and contract negotiation.

[b] Assumes no significant delays due to project financing and/or permitting.

[c] Retrofit of separate ESP module.

[d] An additional 6 months may be required if there are significant space limitations inpacting construction.

site-specific difficulty of retrofitting controls due to site congestion, and the ability of vendors to meet equipment delivery schedules.

2.3.1 Combustion Modifications

The existing MWC population includes a wide variety of combustor designs. Available emissions data indicate that uncontrolled CDD/CDF emissions from operating MWC's span at least three orders of magnitude. This wide range of emissions reflects the variations in combustor designs and operating procedures used in the existing MWC population.

Twelve site evaluations were conducted to examine design and operation characteristics of facilities representing the existing MWC population. Model plants representing subcategories of the existing population were developed based on information gathered at the site visits and through other sources. Baseline uncontrolled emission levels were established for each model using the existing MWC emissions data base, and in some cases, engineering judgement.

The design and operation of each combustor in this study was evaluated against a set of criteria that defines good combustion practice. The focus of the combustion evaluation was directed primarily toward minimization of CDD/CDF emissions. The criteria defining good combustion practice are based on three elements:

1. Design - MWC's must be designed in a manner that will ensure minimization of air emissions.
2. Operation/Control - MWC's must be operated according to their design, and control schemes must be in place which prevent operation outside of the established operating envelope.
3. Verification - Monitors must be in place to verify system performance on a continuous basis.

Table 2.3-3 presents a set of criteria against which the performance of each model plant was evaluated. Satisfying these criteria will ensure that CDD/CDF emissions are minimized. Recommended values for each of the elements are available for most combustion technologies. The recommended values ensure that, in the allowable operating envelope, mixing occurs at sufficient temperatures to destroy CDD/CDF, and that the potential for downstream formation of CDD/CDF is minimized. These are two key premises upon which the combustion recommendations are based. Optimizing the mixing process requires

TABLE 2.3-3. COMBUSTION PARAMETERS USED TO EVALUATE MWC'S

Element	Component
Design	Temperature at fully mixed location Underfire air control Overfire air capacity Overfire air injector design Auxiliary fuel capacity Downstream flue gas temperature
Operation/Control	Excess Air Turndown restrictions Start-up procedures Use of auxiliary fuel
Verification	Oxygen in flue gas CO in flue gas Furnace temperature Adequate air distribution Exit gas temperature

that several design and operating features be addressed. Included among these are temperature at the fully mixed location, control and distribution of underfire (primary) air, design and operating capacity of overfire (secondary) air, and overall system excess air levels. Because no waste-fired system will achieve perfect mixing, the second key requirement of good combustion (downstream temperature control) is necessary. Satisfying this requirement involves control of combustor exit gas temperatures so that flue gases do not experience long residence times at temperatures where CDD/CDF formation occurs.

The other components of good combustion all have specific objectives. The requirement for auxiliary fuel firing capacity ensures that operation during start-up and shutdown conditions results in minimal emissions, and the corrective actions are available in the event that low temperature conditions or high CO emissions occur during normal operation. Turndown restrictions dictate upper and lower load limitations, thus defining the normal operating envelope. The verification measures ensure, through continuous monitoring and periodic testing, that the system is operated according to its design goals. These are important because CDD/CDF emissions cannot be continuously monitored. By maintaining specified levels for parameters such as flue gas CO and O_2 content, furnace combustion and exhaust gas exit temperatures, and air distributions, there will be good assurance that stable combustion conditions and low emission levels are maintained.

The baseline design, operation, and emissions performance of each model plant were examined against the good combustion criteria, and specific areas were identified where adherence to the criteria was lacking. Following this evaluation, combustion retrofits necessary for good combustion were established for each model plant. Each retrofit was a highly site-specific application involving addition or modification of existing equipment or operating procedures, and in some cases, a virtual redesign and rebuild of the entire combustor. The recommended approaches are based on past experiences at existing plants, and in some cases, on engineering judgment.

Estimates of emission reductions associated with a combustion retrofit were made for each model plant. The rationale for establishing the estimated emission reductions is explained in a separate companion report on combustion.[5] In some cases, modifications did not result in reduction of baseline emissions. For example, retrofit of auxiliary fuel burners and CO monitors at a model plant that did not previously include these items would not result directly in lower CDD/CDF emissions. However, they are necessary components of good combustion practice. In other cases, combustion modifications resulted in substantial reduction of CDD/CDF and CO emissions from the baseline.

The final step in the analysis involved development of capital and annual costs for each combustion retrofit. Capital costs were developed based on information available from retrofits made at existing MWC's, and from other similar studies. A description of the costing methodology is presented in a companion document describing cost procedures.[6]

2.3.2 Flue Gas Temperature Reduction

As noted in Section 2.2, CDD/CDF may be catalytically formed in MWC flue gas at temperatures of roughly 500 to 600°F. Cooling CDD/CDF to a temperature of about 450°F or less is expected to inhibit CDD/CDF formation. Exhaust gas cooling also results in condensation of CDD/CDF and some metals, allowing subsequent removal in PM control devices. At least three alternatives are available for lowering temperatures. These include humidification (evaporative cooling) using water sprays, increasing heat transfer area to remove more heat, and dilution of the flue gas with lower temperature air. Cooling the flue gas through humidification or additional heat recovery results in reducing the actual volume of flue gas to be treated and, as a result, should improve the emissions control performance of existing ESP's. Use of dilution air increases the actual flue gas volume and is thus less attractive as a retrofit option if a significant amount of cooling is required. The following sections discuss the use of humidification and heat recovery for flue gas cooling.

Humidification

Humidification is currently used for flue gas cooling at many existing refractory-wall MWC's that do not have heat recovery. In most of these units, water is sprayed into the flue gas in a quench chamber. The hot flue gas evaporates part of the water, resulting in a reduction in flue gas temperature. The temperature of the cooled flue gas can be approximated using the following equation:

$$T_o = T_i - (Q_w * 940 / (Q_g * (1 - W_{\%v} / 100)))$$

where T_o is the outlet flue gas temperature (^oF), T_i is the inlet flue gas temperature (^oF), Q_w is the quantity of water evaporated (lb/hr), Q_g is the flue gas flow rate (scfm), and $W_{\%v}$ is the volume percent moisture in the inlet flue gas.

If the size of the sprayed water droplets is sufficiently small and the flue gas residence time and inlet temperature are sufficiently high, all of the sprayed water will evaporate. If not, unevaporated water will collect on the walls and bottom of the quench chamber. This water is then either recirculated or discharged. To increase the amount of cooling, the quantity of water sprayed is increased while the mean particle size of the spray droplets is decreased. Through proper sizing of the quench chamber (i.e., residence time) and spray system (i.e., water feed rate and mean droplet diameter), flue gas cooling can be accomplished over a wide range of inlet and outlet flue gas temperatures.

For each of the model plants, the design flue gas temperature at the humidification chamber outlet is 450^{o}F. At this temperature, CDD/CDF levels at the PM control device inlet and exit are expected to be roughly equal. Flue gas temperature at the humidification chamber inlet is assumed to be the same as the flue gas temperature at the combustor outlet.

The design of the humidification system used for each model plant varies depending on whether the model is already equipped with a spray chamber. If the model plant is already equipped with a spray chamber, additional flue gas cooling can be accomplished by increasing the flow and atomization pressure of water sprays.

For model plants without an existing humidification system and with flue gas temperatures above 450^{o}F, retrofit of a humidification chamber is necessary. This chamber is designed to achieve complete evaporation of the sprayed water (i.e., no liquid discharge). Design flue gas velocity is 10 feet/second and the chamber length-to-diameter ratio (L/D) is 3. To minimize PM fallout and impingement of wetted solids on chamber walls, no baffles or other internals are used. High-pressure nozzles are used for water atomization. To minimize MWC downtime associated with retrofit, the humidification chamber is assumed to be constructed as a modular system. Through appropriate construction planning, the chamber can then be installed into the existing flue gas ducting with minimal downtime of the combustor.

Additional Heat Transfer Surface

A second approach for reducing MWC exhaust gas temperatures at energy recovery facilities is to install additional heat transfer surface. Municipal waste-fired boilers are generally designed with radiant and convective sections. The quantity of heat removed in the convective section is directly proportional to the amount of tube surface area available for convective heat transfer. For a boiler with a constant heat input (firing rate) and gas velocity, additional exhaust gas temperature reduction can be achieved by providing more tube surface area.

The typical application of this retrofit can involve the addition of a bank of economizer tubes, replacement of an existing economizer with a redesigned unit, or addition of a separate economizer where none previously existed. There are limitations to this retrofit, however, including potential space constraints and practical limits on operating temperatures (steam side and gas side). Because it is generally undesirable for steaming to occur in the economizer, there are limitations on the amount of flue gas temperature reduction that can be accomplished. Applications at one modular facility and one mass burn waterwall facility have reduced flue gas temperatures from 570 to 600°F down to 350 to 450°F prior to entering the ESP, thus minimizing the gas residence time at temperatures where CDD/CDF formation may occur.[11,12]

An added benefit of increased heat recovery is improved boiler efficiency. As a rule of thumb, a 25°F drop in exit gas temperature equates to a 1 percent increase in boiler efficiency.[13] For example, reducing the economizer gas temperature from 600°F to 450°F boosts boiler efficiency by about 6 percent, with an attendant increase in steam production and potential revenues. Therefore, incentives exist both from an economic and an environmental standpoint to maximize the removal of available heat through the boiler and provide lower exit gas temperatures. The lower temperature boundary is dictated by concerns over acid gas dewpoint. Currently there are few, if any, ESP's operating at temperatures below 350°F, unless acid gas removal is included in the system design.

2.3.3 Particulate Matter Control

A variety of PM control technologies are in use by existing MWC's, including ESP's, fabric filters, electrostatic gravel bed filters, cyclones, and venturi scrubbers. The most common of these devices currently in use is the ESP. When properly designed and operated, ESP's are capable of achieving high levels of PM control. Very limited data are available for the control efficiency of other PM control devices applied to MWC's. Therefore, the analysis of retrofit PM control options was limited to ESP's.

Two levels of retrofit PM control were considered, "good" control as reflected by 40 CFR 60, Subparts Db and E, and "best" control as reflected by current best available control technology (BACT). Subpart Db limits PM emissions from new units with heat recovery and heat input rates of 100 million Btu/hr and greater to roughly 0.05 gr/dscf, while Subpart E limits PM emissions from all other MWC's greater than 50 tpd to 0.08 gr/dscf. Based on State or other permit requirements, a number of existing MWC ESP's are currently operating with PM emissions of 0.01 to 0.03 gr/dscf.[14] Technical alternatives for reducing emissions from existing MWC's included rebuild of the existing ESP, increasing the plate area of the existing ESP, and installation of a new ESP.

Rebuild of an existing ESP may be feasible for ESP's with PM removal efficiencies lower than achievable with a new ESP of equivalent specific collection area (SCA, equal to the total plate area divided by the flue gas flow rate). An ESP rebuild includes replacing worn and damaged internal components (e.g., plates, frame, electrodes), upgrading of controls and electronics for more effective energization, and flow modeling to improve flue gas distribution. A rebuild does not include changing plate-electrode geometry or adding plate area.

Installation of additional plate area can be used when the existing ESP has insufficient plate area to achieve the required PM emission limit. In this study, this additional plate area was installed as a second ESP located in series downstream of the existing ESP. This approach was used to minimize facility downtime and simplify cost estimating relative to addition of plate area to an existing ESP. In concept, locating the new ESP in series is analogous to adding one or more additional new fields to the existing unit.

Installing a new ESP may be required if the MWC does not have an ESP or the existing ESP cannot be upgraded to achieve the required level of PM control. In this study, the cost of the new ESP was estimated by escalating the cost of a new ESP based on space limitation and other retrofit costs specific to each model plant.

2.3.4 Acid Gas Control

Except for facilities constructed or modified in recent years, acid gas controls are not used at most existing MWC's in the U. S. Emission test data obtained from recently built units indicate that acid gas controls combined with efficient PM control can achieve significant reductions in acid gases, CDD/CDF, and volatile metal emissions.[14] Removal of acid gases is achieved by chemical reaction with alkali sorbents. Current information suggests that removal of CDD/CDF results from condensation of organics at reduced temperatures and their subsequent collection in an efficient PM control device. Available data indicate a fabric filter is needed to achieve maximum reductions of CDD/CDF and mercury.

Two alternatives for acid gas control are considered in this study: spray drying followed by a retrofit fabric filter and dry sorbent injection combined with reuse of existing ESP's. The spray drying/fabric filter alternative was used to evaluate the emission reductions, costs, and other impacts associated with maximum reductions in air emissions. The dry sorbent injection/ESP reuse alternative was used to evaluate a lesser level of emissions control, with a lower cost impact.

The major components in a spray drying system are the slurry preparation system, the slurry atomizer and reaction vessel, and the PM collection systems. The slurry, consisting of alkali sorbent (typically lime) and water are injected into the flue gas at a prescribed stoichiometric ratio to cool the flue gas and to achieve the desired acid gas removal efficiencies. High removal efficiencies for HCl (97 percent) and SO_2 (90 percent) have been demonstrated by spray dryers operating at stoichiometric ratios of near 2.5 and a fabric filter operating temperature of 250 to 300^{0}F. Removal efficiencies for CDD/CDF with spray dryer and fabric filter systems have exceeded 99 percent, with outlet concentrations less than 10 ng/dscm.[14] If an ESP is used for PM control, achievable emission reductions will be lower.[14]

Spray drying was used to evaluate the environmental, economic, and energy impacts of "best" acid gas control. System design was based on a sorbent-to-acid gas stoichiometric ratio of 2.5, exit flue gas temperature of 300°F, and installation of a new fabric filter following the spray dryer. Estimated long-term emission reductions were 97 percent for HCl, 90 percent for SO_2, and 99 percent for CDD/CDF with a maximum CDD/CDF outlet concentration of 5 ng/dscm. As with temperature and PM controls discussed previously and subject to model plant space limitations, most of the spray dryer system construction activities can occur while the MWC is still operating, thus limiting MWC downtime in most cases to system tie-in and start-up.

Dry sorbent injection either directly into the combustor or in a downstream duct has been used on MWC's in Japan and Europe since the late 1970's, and has recently been installed on several MWC's in the U. S. Most of the performance data is limited to acid gas control with only limited CDD/CDF data currently available. The major components in dry injection systems include sorbent storage and transport, sorbent injection, flue gas temperature control, and PM collection. As with spray drying, emission reduction potential is a function of sorbent feed rate, flue gas temperature, and the type of PM control device. Because flue gas temperatures in the PM control device of retrofit dry injection systems are likely to be higher than for spray dryer systems (350 to 450°F versus 250 to 300°F), acid gas removal efficiencies with dry injection systems are expected to be lower than with spray dryers.[14]

Dry sorbent injection was used to evaluate "good" acid gas control. In this case, the focus was on achieving reasonable acid gas and CDD/CDF reductions while minimizing emission control system costs. System design was based on a sorbent-to-acid gas stoichiometric ratio of 2.0, flue gas cooling to 350°F, and reuse of the existing ESP (with upgrade if necessary to achieve average PM emissions of 0.01 gr/dscf). Estimated emission reductions in this case were 80 percent for HCl, 40 percent for SO_2, and 75 percent for CDD/CDF. For the two model plants that did not have an existing ESP, a new fabric filter was installed with the DSI system and the exit flue gas temperature was reduced to 300°F. Emission reductions for HCl, SO_2, and

CDD/CDF from this system were assumed to be the same as discussed above. Except for systems with very short or tight flue gas arrangements, sorbent was injected into the cooled flue gas downstream of the humidification system. Where duct configurations were limiting, injection of sorbent directly into the combustor was assumed. As with spray dryer systems, construction activities were scheduled to occur while the MWC is still operating, thus reducing MWC downtime except for system tie-in and start-up.

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3.0 DEFINITION OF CONTROL OPTIONS

Seven emission control options are considered for existing sources. The seven options are combinations of the four types of control technologies described in Section 2.3. The same seven control options apply to each model plant. The baseline level of combustion control and add-on control for the model plants vary with combustor type, unit size, age, and prevalence of APCD's at existing facilities represented by the model plant. In some cases, a model plant at baseline is already controlled to the level of some of the control options. In such cases, there are no cost or emission reductions associated with those options for that particular model plant. Only one level of combustion modification ("good combustion" as described in Section 2.3) was evaluated. The seven retrofit control options are described below:

Option 1 "Good Combustion and Temperature Control"
- good combustion
- exhaust gas temperature control to 450°F
- baseline PM control
- no acid gas control

Option 2 "Good Combustion and Temperature Control with Good PM Control"
- good combustion
- exhaust gas temperature control to 450°F
- good PM control (0.05 gr/dscf)
- no acid gas control

Option 3 "Good Combustion and Temperature Control with Best PM Control"
- good combustion
- exhaust gas temperature control to 450°F
- best PM control (0.01 gr/dscf)
- no acid gas control

Option 4 "Good Acid Gas Control with Best PM Control"
- baseline combustion control
- exhaust gas temperature control to 350°F
- good acid gas control - dry sorbent injection
- best PM control (0.01 gr/dscf)

Option 5 "Good Combustion and Temperature Control with Good Acid Gas Control and Best PM Control"
- good combustion
- exhaust gas temperature control to 350°F
- good acid gas control - dry sorbent duct injection
- best PM control (0.01 gr/dscf)

Option 6 "Best Acid Gas Control with Best PM Control"
- baseline combustion control
- exhaust gas temperature control to 300°F
- best acid gas control - spray dryer
- best PM control (0.01 gr/dscf)

Option 7 "Good Combustion and Temperature Control with Best Acid Gas Control and Best PM Control"
- good combustion
- exhaust gas temperature control to 300°F
- best acid gas control - spray dryer
- best PM control (0.01 gr/dscf)

4.0 MASS BURN REFRACTORY-WALL COMBUSTORS

Prior to the 1970's, there were hundreds of municipal waste combustors (MWC's) burning refuse in the United States. The goal of these plants was to achieve waste volume reduction; energy recovery was not incorporated into their designs. Due to a number of reasons--economic, environmental, and plant age--most of the municipal combustors ceased to operate during the 1970's. Some of these refractory-wall plants were replaced by energy recovery plants. Others were replaced by landfills. The handful of refractory-wall plants that still operate do so with largely outdated technology. In addition, the increasing limitations of available space for landfills may cause some older refractory-wall plants to renew operation with revamped designs. This section describes the current design and operation of older refractory-wall combustors, and identifies design and operating features which may contribute to air emissions.

The existing population of mass burn refractory-wall MWC's consists of more than 20 operating plants. Table 4.0-1 lists the mass burn refractory-wall plants that remain in operation as of 1988. Included in the table are grate type, number of units, unit capacity, year of start-up, and air pollution control device (APCD) in place at each plant. Although none of the plants were originally constructed with heat recovery capabilities, at least two refractory-wall combustors (Waukesha, WI and Betts Avenue, NY, NY) have been retrofit with a waste heat boiler, and three additional plants (North and South Dayton, OH and Tampa, FL) are considering adding boilers in the future. Most plants in this category use electrostatic precipitators (ESP's) for particulate control. However, a number of the plants use a wet particulate control device such as a wet scrubber. One plant (Framingham, MA) is equipped with a spray dryer and fabric filter. Most of these plants are publicly owned, and operate on a 24-hour/day, 5-day/week schedule with weekend shutdowns.

At least three distinct combustor designs make up the existing population of refractory-wall combustors. The first design is a batch-fed upright combustor, which may be cylindrical or rectangular in shape. Very few of these systems continue to operate. Three units have been identified

TABLE 4.0-1. EXISTING MASS BURN REFRACTORY-WALL COMBUSTORS

Plant/Location	Grate Type	No. of Units	Unit Size (tpd)	Year of Start Up[a]	Air Pollution Control Device
Batch Feed					
Stamford I, CT		1	150	1953	Electrostatic Precipitator
Huntington, NY		2	150	NA	Water Sprays
Continuous Feed					
Philadelphia NW, PA	Traveling	2	375	1957	Electrostatic Precipitator
Philadelphia EC, PA	Traveling	2	375	1965	Electrostatic Precipitator
East Chicago, IN	Traveling	2	225	1971	Venturi Scrubber
SE Oakland County, MI	Traveling	2	300	1965	Venturi Scrubber
Honolulu, HI	Traveling	2	300	1970	Electrostatic Precipitator
New York, NY (Betts Ave.)	Traveling	4	250	NA	Electrostatic Precipitator
Clinton, MI	Reciprocating	2	300	1972	Electrostatic Precipitator
Euclid, OH	Reciprocating	2	100	1955	Electrostatic Precipitator
Fall River, MA	Reciprocating	2	300	1972	Wet Scrubber
New Canaan, CT	Reciprocating	1	125	1971	Venturi Scrubber
Washington, DC	Reciprocating	4	250	1972	Electrostatic Precipitator
Baltimore, MD (Pulaski)	Reciprocating	4	300	NA	Electrostatic Precipitator
SW Brooklyn, NY	Reciprocating	4	240	1959	Electrostatic Precipitator
Waukesha, WI	Reciprocating	2	88	1971	Electrostatic Precipitator
Stamford II, CT	Rocking	1	360	1974	Electrostatic Precipitator
Sheboygan, WI	Rocking	2	120	1965	Water Sprays
Huntington, NY	Rocking	1	150	1963	Electrostatic Precipitator
North Dayton, OH	Grate/Rotary Kiln	3	300	1970	Electrostatic Precipitator
South Dayton, OH	Grate/Rotary Kiln	3	300	1970	Electrostatic Precipitator
Louisville, KY	Grate/Rotary Kiln	4	250	1956	Wet Scrubber
Framingham, MA	Grate/Rotary Kiln	2	250	1970	Dry Scrubber/Fabric Filter
Tampa, FL	Grate/Rotary Kiln	4	250	1985	Electrostatic Precipitator

[a] NA - Information not available.

in the existing population (Stamford I, CT, and two units at Huntington, NY). The Stamford unit is rated at 150 tpd and is equipped with a water quench and an ESP. The units in Huntington, NY are reported to have unit capacities of 150 tpd and use water sprays to control emissions prior to discharge through individual stacks. All three of these units were constructed prior to 1960. Figure 4.0-1 shows the typical configuration of a batch-fed rectangular combustor. This type of combustor was prevalent in the 1950's, but no additional units of this design are expected to become operable.

A second, more common design consists of rectangular combustion chambers with traveling, rocking, or reciprocating grates. This type of combustor is continuously fed and operates in an excess air mode. The primary distinction between plants with this design is the manner in which the waste is moved through the combustor. A schematic of a traveling grate combustor is shown in Figure 4.0-2. The traveling grate moves on a set of sprockets and does not agitate the waste bed as it advances through the combustor. As a result, waste burnout is inhibited by fuel bed thickness, and there is considerable potential for unburned waste to be discharged from the grates unless fuel feeding, grate speeds, and combustion air flows and distributions are well controlled. It is unlikely that these operational requirements are routinely accomplished in existing units. As shown in Table 4.0-1, there are six mass burn plants currently operating which use traveling grates. The average unit capacity for the operating plants is approximately 300 tpd.

There are eleven mass burn refractory-wall plants in operation that use rocking or reciprocating grates. The average unit capacity of these plants is 230 tpd. While none of these systems represent state-of-the-art combustion practice, rocking or reciprocating grates have advantages over traveling grates. Rocking and reciprocating grate systems agitate and aerate the waste bed as it advances through the combustion chamber, allowing more waste surface area to be exposed to the combustion air and increasing burnout of combustibles. The configuration and operation of a rocking grate section is shown in Figure 4.0-3.

The last major design type in the mass burn refractory-wall population is a system which combines grate burning technology with a rotary kiln.

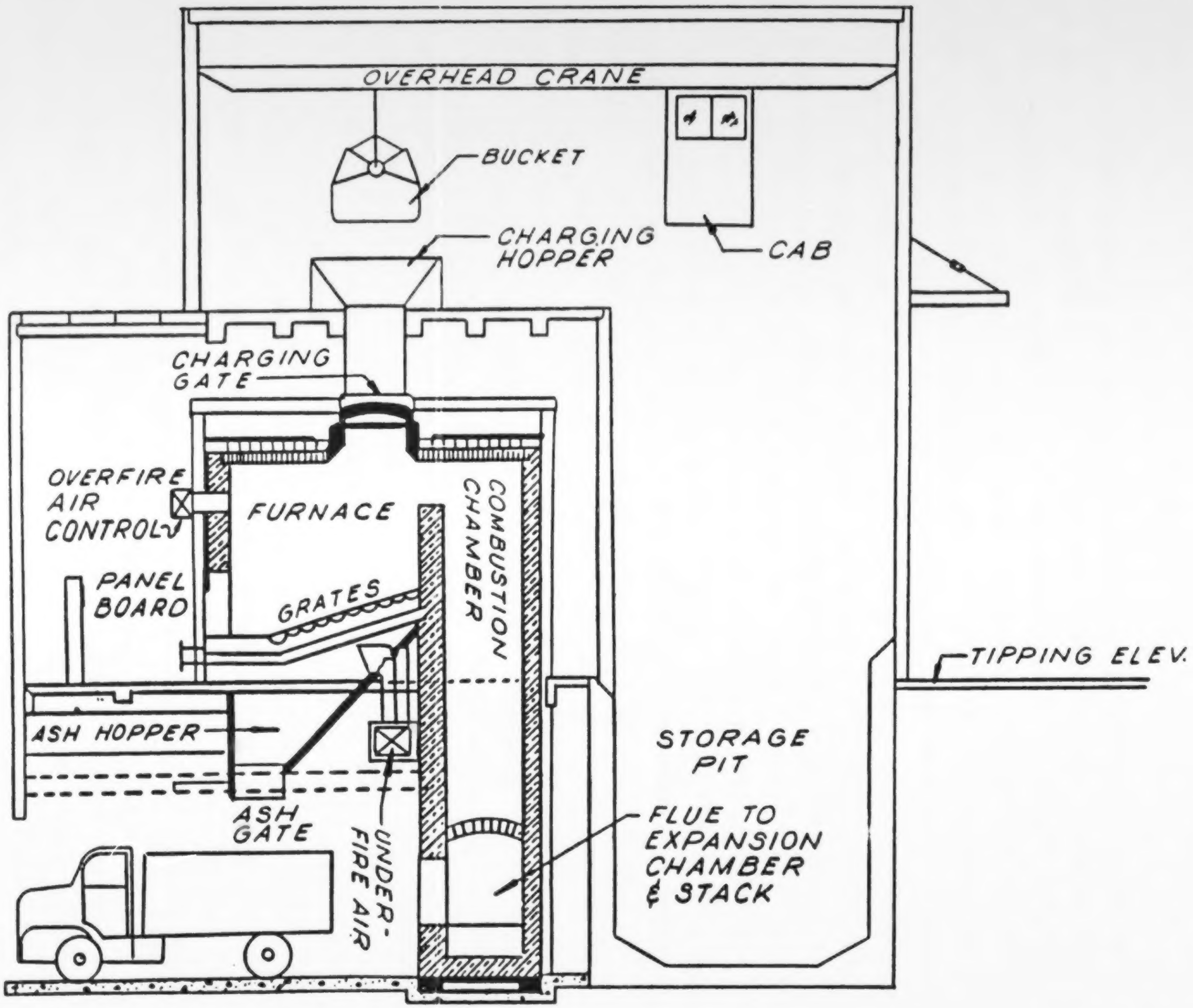

Figure 4.0-1. Refractory-Wall Batch Combustor

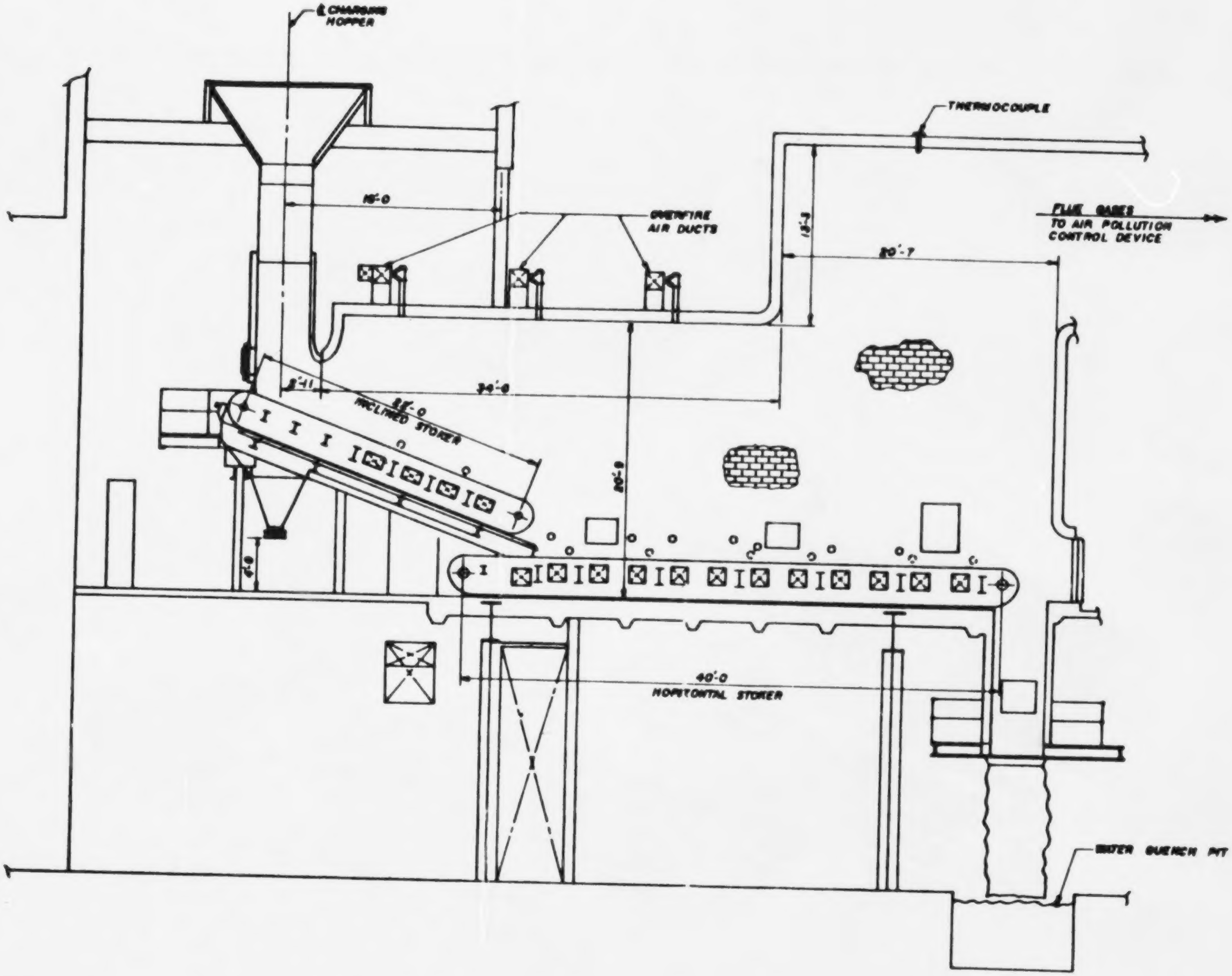

Figure 4.0-2. Mass Burn Refractory-Wall Combustor with Traveling Grate

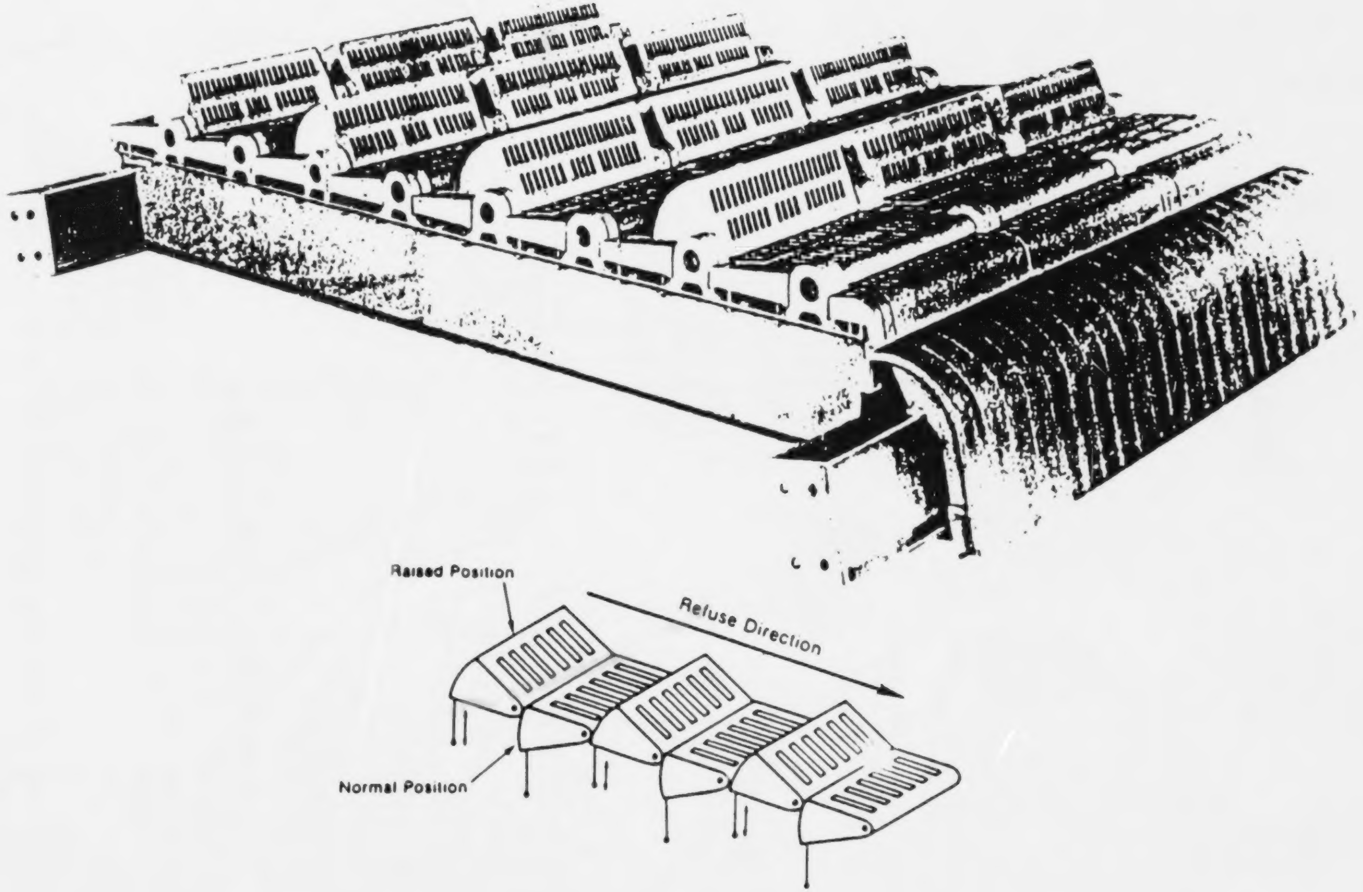

Figure 4.0-3. F&E (Flynn & Emrick) rocker grate (F&E Stokers, Inc. and Hickman, et al., 1984)

Figure 4.0-4 shows a schematic of this design. Two grate sections (drying and ignition) precede a refractory-lined rotary kiln, where combustion is completed. There are five existing plants in this subcategory, and the average size among these units is 250 tpd.

For this study, three model plants representing refractory-wall combustors were developed. The models were selected to be representative of the most typical designs in the refractory-wall population. The first uses a traveling grate and has an ESP for flue gas cleaning. The second has a rocking grate and a wet baffled system for flue gas cleaning. The third model plant is of the grate/rotary kiln design, and has an ESP. Descriptions and analyses of these model plants are presented in the Sections 4.1 through 4.3.

There are a number of inherent design features and operating practices in place at these refractory-wall MWC's which cause elevated emission levels of air pollutants. Some of the primary areas of concern include:

1. Fuel feeding
2. Combustion air distribution and control
3. Excess air levels
4. Start-up/shutdown procedures
5. Temperature control

These topics are discussed below.

Fuel Feeding

While ram feeders are employed in a few units, it is more typical for this type of plant to utilize a gravity feed system. In this instance, control of fuel feeding is achieved by adjusting the grate speed directly below the feed chute. This is typically a manual adjustment. In general, grate speeds should be adjusted so that the waste feed is evenly distributed on the grates, with the majority of burning being concentrated in the middle portion of the grate. Problems may occur as waste properties (i.e., moisture) change, resulting in clumping and poor distribution of waste on the grate and, hence, potential burnout problems. Reciprocating and rocking grates have the ability to minimize these problems by continually agitating and aerating the fuel bed, but traveling grates cannot respond to changes in fuel properties. Therefore, traveling grates are not acceptable technology for mass burn systems.

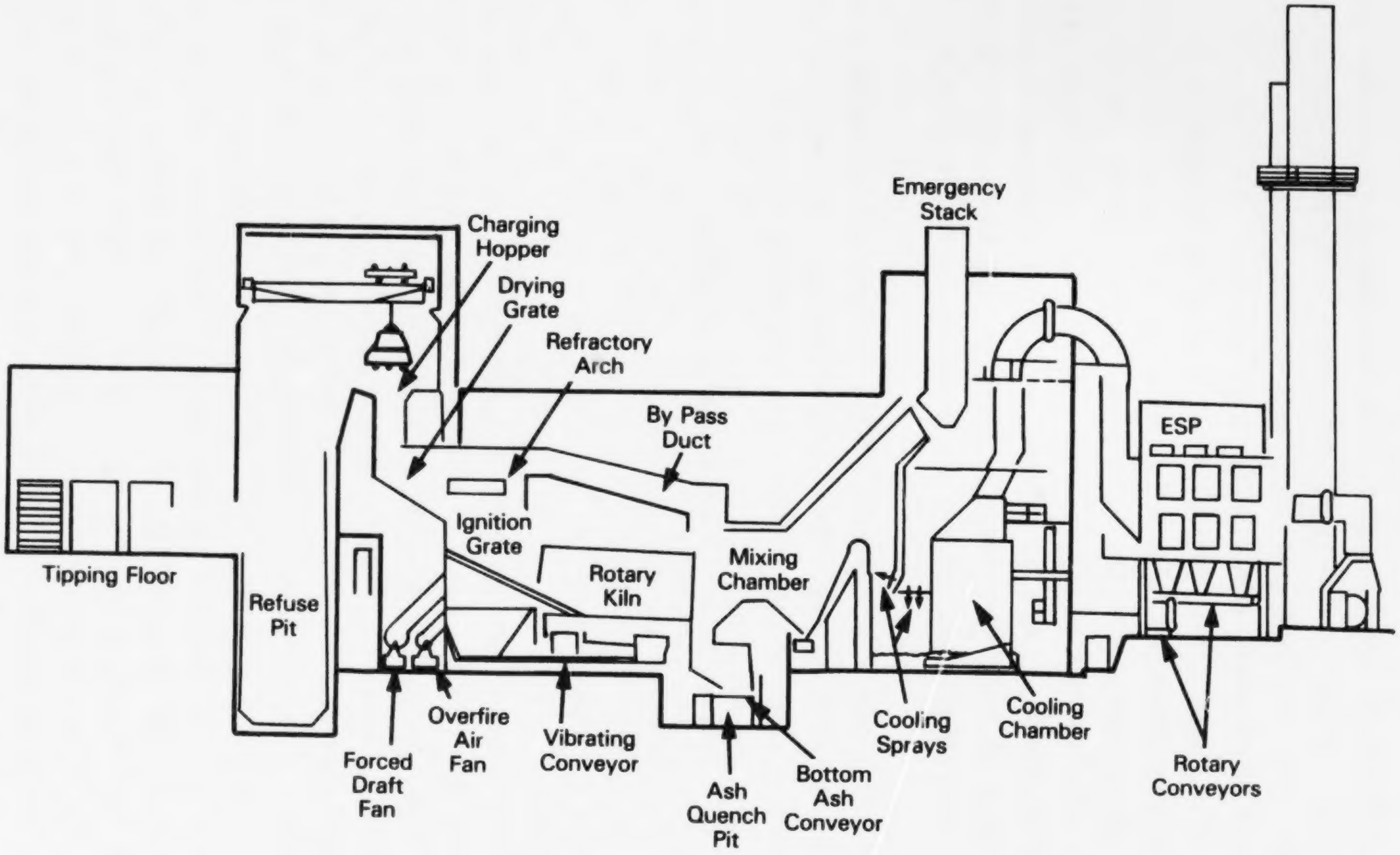

Figure 4.0-4. Mass Burn Refractory-Wall Combustor with Grate/Rotary Kiln

A second problem with gravity feed systems relates to maintaining proper combustor drafts. Combustor seals are maintained by the waste in the feed chute. Episodes where the hopper seal is broken contribute to problems in combustor draft control and have an adverse effect on combustion conditions. Unstable combustor drafts can result in upsets which affect air flows, temperatures, and air emissions. Use of ram feeders can minimize these episodes.

Combustion Air Distribution and Control

A number of deficiencies in combustion air flows can potentially occur in older refractory-wall combustors. The amount, location, and distribution of combustion air are all critical to ensuring that organic species emitted from the burning waste bed are oxidized to the maximum extent possible. Available information for this category of MWC's indicates that combustion air systems are generally inadequate to provide good combustion and minimize levels of trace organic emissions.

Good combustion practice requires that underfire air be adequately distributed to the waste on the grate to provide proper burnout. This is necessary to complete the burning process prior to discharge of ash from the end of the grate. Underfire air distribution can be optimized by using at least four separate underfire air plenums. The ability to individually monitor and control underfire air pressures or flow rates to each plenum is also a necessary element of good combustion.

Mass burn refractory-wall combustors typically have overfire air designs which do not provide adequate mixing for minimizing organic emissions. Rather than providing penetration and coverage of the combustor cross section, the overfire air systems simply inject air for dilution and cooling. There is no well-defined point in the system where mixing is complete. In addition, air flows are seldom measured or monitored, and adjustments are left to the experience of the operator. It is important that overfire air systems be designed to supply an adequate quantity of air in a location which provides penetration and coverage of the combustor cross-section to ensure good mixing and complete combustion. Failure to achieve good mixing can result in higher levels of CO and organic emissions, and greater particulate carryover out of the combustor. The number, diameter, velocity, and arrangement of overfire air nozzles all contribute to the proper design and operation of the system. Nozzle header pressures are typically measured to provide verification of velocities and flows. Overfire air patterns can best be established as a result of cold flow modeling. Verification of mixing should be established by continuous CO monitoring. It is doubtful that many existing refractory-wall combustors are equipped with continuous CO monitors.

Combustor Excess Air Levels

Refractory-wall combustors typically operate at higher excess air rates (150 to 300 percent) than mass burn waterwall combustors (80 to 100 percent). This is because refractory-wall combustors contain no heat transfer medium such as the waterwalls which are present in modern energy recovery units. The higher design excess air levels are specified to prevent excessive temperatures which can result in refractory damage, slagging, fouling, and corrosion problems. Figure 4.0-5 illustrates the relationship between excess air levels (expressed as a percentage of stoichiometric air) and adiabatic flame temperature. Adiabatic flame temperature is the theoretical maximum temperature that can be achieved, assuming that perfect mixing is achieved and that no heat loss occurs. When applying this relationship to refuse-fired systems, the adiabatic flame temperature can be considered analogous to the maximum theoretically achievable mass mean gas temperature at the fully mixed location. As shown in Figure 4.0-5, the highest theoretical temperature occurs at stoichiometric conditions, and as excess air levels increase, the adiabatic flame temperature is reduced. For a fuel with 20 percent moisture content (typical of MSW), the adiabatic flame temperature of 1800^{0}F occurs at 150 percent excess air. At excess air levels of greater than 150 percent, the 1800^{0}F temperature cannot be attained. Thus, it is recommended that the 150 percent excess air be selected as an operating target (maximum) for refractory-wall MWC's.

One adverse effect of higher excess air levels is the potential for increased carryover of PM from the combustion chamber and ultimately stack emission rates. It is hypothesized that high PM carryover may also contribute to increased CDD/CDF emissions by providing increased surface area for downstream catalytic formation to take place. A second problem is

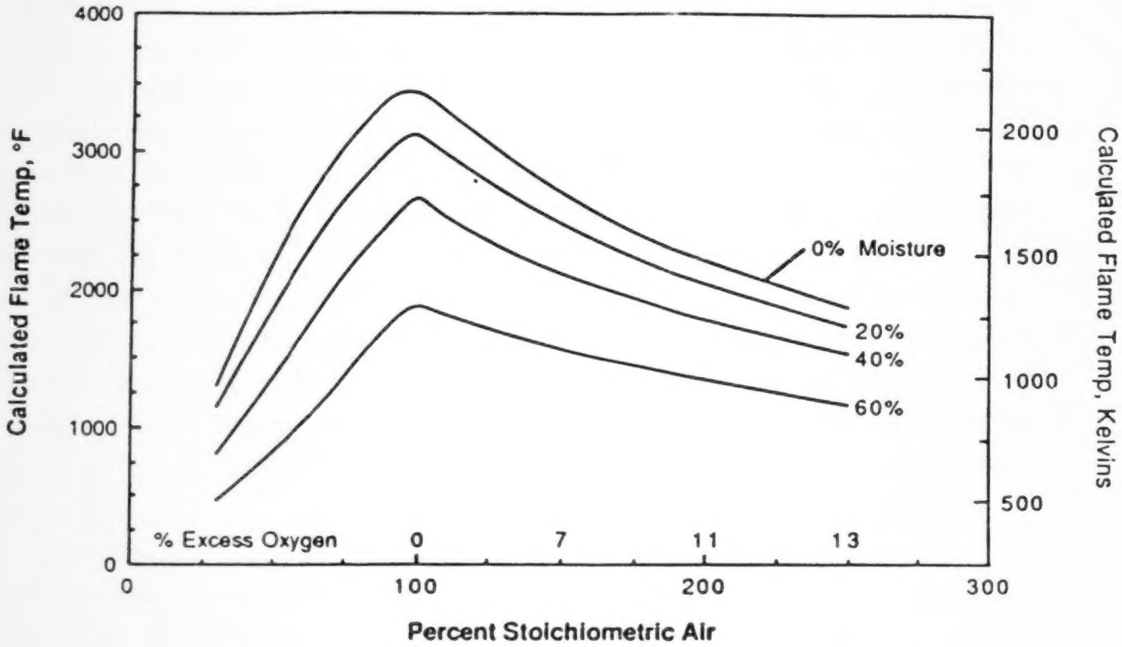

Figure 4.0-5. Theoretical temperature of products of combustion as a function of excess air for unprocessed MSW with feed characteristics typical of raw waste in Table 2.2-1.

the potential for high excess air levels to quench the combustion reactions, preventing destruction of organic species. Because there are problems with operating an excess air level too low or too high, systems must select an excess air level which allows for both safe operation and minimal emissions.

Oxygen monitors are used in mass burn waterwall MWC's to verify excess air levels. Few, if any, older refractory-wall combustors are equipped with oxygen monitoring. Oxygen monitoring is an important means of verifying performance so that air flows can be optimized.

Start-up/Shutdown Procedures

The majority of refractory-wall combustors are municipally owned and operated, and typical operating schedules include five days on line with shutdowns on weekends. Start-ups and shutdowns are episodes during which CDD/CDF emissions are expected to be above normal operating levels. A substantial number of the combustors currently operating are not equipped with auxiliary fuel sources for process start-up and shutdown. Auxiliary fuel firing capabilities are required for good combustion practices and should be included in the design of all MWC's. If a system shuts down over the weekend, one operating procedure that will enable start-up time to be minimized is to keep all combustor seals intact, enabling the system to act as a "thermos bottle" and retain available heat so that a totally cold start is avoided. This is a standard operating procedure for many refractory-wall combustors.

Temperature Control

All mass burn MWC's must have the ability to maintain combustion temperatures above 1800^{O}F as part of good combustion. Refractory-wall MWC's should have no problem attaining this combustion temperature if the above described design and operating features are in place. However, recent bench-scale and full-scale data suggests that CDD/CDF formation may also occur in the low temperature regions of the waste combustion system. Available data indicates that CDD/CDF formation is maximized at temperatures between 500 and 600^{O}F. This is a typical operating temperature range for many ESP's in the waste combustion industry. Based on the available data it appears that formation does not occur at temperatures in the range of 450^{O}F or less.

Therefore, existing systems must attempt to minimize retention time of flue gases in the range of 500 to 600°F by lowering ESP operating temperatures. Refractory-wall combustors are equipped to address this problem through the use of existing water sprays.

4.1 TRAVELING GRATE MASS BURN REFRACTORY-WALL COMBUSTOR

This section presents the retrofit case study results for a mass burn refractory-wall combustor equipped with a traveling grate. As shown in Table 4.0-1, there are six known plants in this subcategory. Section 4.1.1 presents a description of the Philadelphia Northwest (NW) MWC plant which was visited in order to gather information for model development. Section 4.1.2 describes the model plant. Sections 4.1.3 through 4.1.7 detail the retrofit modifications, estimated performance, and costs associated with various control options. Section 4.1.8 summarizes the control options, which are discussed in more detail in Section 3.0 of this report.

4.1.1 Description of the Philadelphia Northwest Plant[1]

The Philadelphia NW plant consists of two identical refractory-wall combustors, each with a design capacity of 375 tons of municipal solid waste (MSW) per day. Table 4.1-1 presents key design data for the plant. The facility has been in operation since 1957 and processes an estimated 25 percent of the city's municipal waste, burning waste 5-days/week with weekend shutdowns. The plant accepts no commercial or industrial waste and does not charge a tipping fee. Individuals are permitted to dump household waste at the plant during designated hours. There are two 2,850 cubic yard waste holding pits at the plant which are emptied by two overhead cranes equipped with clamshell buckets.

4.1.1.1 Combustor Design and Operation. Each refractory-lined combustor consists of a water-jacketed gravity-feed chute, an inclined traveling grate, a horizontal traveling grate, and an ash discharge chute. The feed rate to each combustor is controlled by the speed of the inclined grate. A 4-1/2 foot vertical drop separates the inclined grate and the horizontal grate. The speed of the horizontal grate controls the depth of the waste bed. Bottom ash is discharged from the end of the horizontal grate into a water quench pit. The water level in the quench pit is designed to maintain a pressure seal between the combustor and the ash handling system. The water level is controlled by an automatic float valve.

The traveling grates do not provide any agitation of the waste bed as it moves through the furnace. As a result, burnout of the waste is not

TABLE 4.1-1. PHILADELPHIA NORTHWEST DESIGN DATA

Combustor (two identical combustors):

Capacity - 375 tons per day each
Grate Area - 480 square feet each
  Inclined Grate - 8 feet wide by 22 feet long, 20° incline
  Horizontal Grate - 8 feet wide by 40 feet long
Combustor Dimensions - Each combustor consists of two connected chambers (See Figure 4-1.1)
  Lower Chamber - 55 feet long by 8 feet wide by 21 feet high
  Upper Chamber - 21 feet long by 8 feet wide by 13 feet high
Exit Breeching - rectangular, 8 feet by 7 feet

Gas Conditioning (identical for each combustor):

1 Spray Tower and
1 Evaporation Tower - 14 feet in diameter by 42 feet high (each)
Water Spray - 100 gpm, first tower only

Emission Controls (identical for each combustor):

Type - 2-field ESP
Manufacturer - Combustion Engineering
Gas Flow - 219,000 acfm at 550°F
Collecting Area - 47,000 square feet
SCA - 215 square feet per 1000 acfm
Dimensions - 11 x 33 x 22.4 feet (11.2 feet per field)
Gas Velocity - 4 ft/sec
Gas Residence Time - 6 seconds
Collection Efficiency - 97.5%
Exit Concentration - 0.02 gr/dscf at 12 percent CO_2

completed prior to discharge from the horizontal grate to the quench pit. Based on visual observation, it was estimated that waste volume reductions are no greater than 50 to 75 percent.

The original furnace configuration included a rectangular chamber with a height of approximately 17 feet from the top of the horizontal stoker to the roof. At a point 34 feet from the front wall the roof height increased to about 32 feet, forming the upper rectangular combustion chamber, which was a burnout area for volatiles. The length of this chamber was 20 feet, 7 inches. Combustion gases originally passed from the burnout chamber through a rectangular opening approximately 8 feet by 12 feet, 8 inches to the flue gas cleaning system. Figure 4.1-1 shows the original combustor profile.

Several modifications have recently been made to each of the combustors. First, the configuration of the upper combustor chamber was altered by addition of structural steel refractory-lined arches on the front and rear walls of the chamber to reduce the cross-sectional area of the inlet to the upper chamber from its previous dimensions of 8 feet by 21 feet to an opening 8 feet wide by about 7 feet long. In addition, a vertical baffle was installed at the exit of the combustion chamber, and the water sprays which were previously at that location were moved approximately 25 feet downstream into the first tower. These modifications were made in an attempt to increase mixing and flue gas retention time. Other facilities of this type are not expected to have these types of modifications.

A single forced-draft fan provides underfire air to both grates and overfire air to 3 rows of nozzles located on the top of the lower combustion chamber. There are 4 underfire plenums beneath the inclined grate and 6 plenums beneath the horizontal grate. Each plenum has a separate manually operated damper to adjust air distribution. Each of the 3 overfire air rows consists of seven 4-inch diameter nozzles on 12-inch centers. The first row is above the inclined grate near its center. The second row is located directly above the end of the inclined grate, and the third row is above the horizontal grate approximately one-third of the way along its total length. Each row has an individual damper which is either fully open or fully closed. No accurate estimates of underfire/overfire air splits are available.

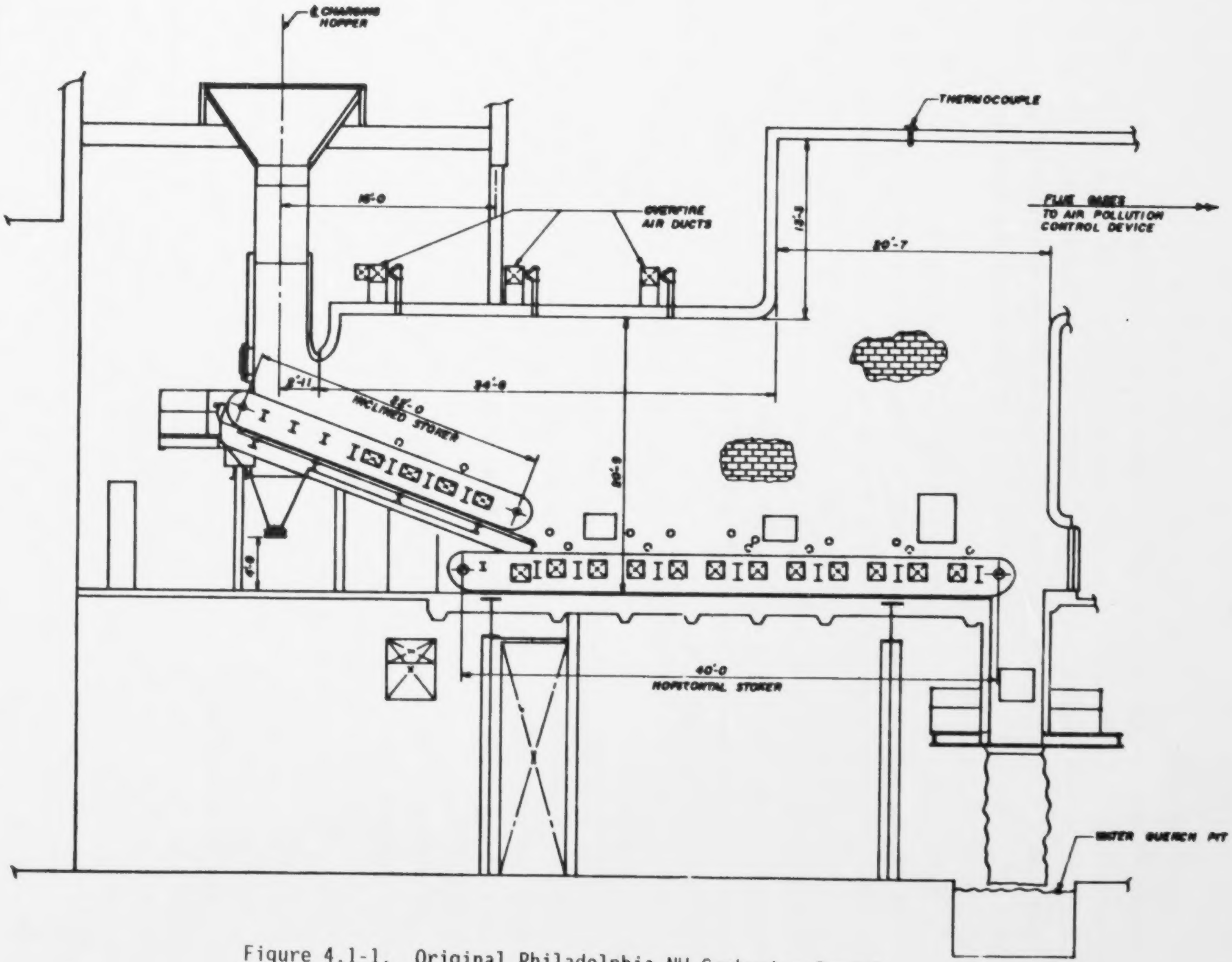

Figure 4.1-1. Original Philadelphia NW Combustor Profile

A second forced-draft fan supplies wall cooling air, which is introduced into the combustion chamber through six 4-inch diameter nozzles on each side of the combustor at a level approximately 6 inches above the top of the horizontal grate. Additional overfire air ports which were located about 1-1/2 foot above the horizontal grate are now bricked over and inoperable. Silicon carbide blocks line the lower portion of the combustor to a height of 2 to 3 feet above the grates.

There are a number of sources of air leakage to the combustor, including the space where the waste drops from the inclined grate to the horizontal grate. A steel plate with a viewing port has been constructed at this location to prevent projectiles from shooting out of the combustor, but the plate does not restrict airflow into the combustor. This area was originally open. Inspection ports are also located on the upper front wall of the combustion chamber, and on the rear wall where the horizontal grate dumps into the ash quench pit.

The combustor has a local requirement to operate above 1,400°F in order to minimize odors. This temperature is verified by two thermocouples located on the side walls in the rear of the combustor. These readings are continuously recorded on a circular chart on the control panel in the Plant Superintendent's Office. The temperatures are maintained by manually adjusting combustion air flows and MSW feed rates. No automatic controls are available.

Variation of the combustion air distribution is left to the discretion of the operator based on his visual observation of the flame patterns in the combustor. An automatic draft control provides feedback to the induced-draft fan; a negative draft of 0.2 to 0.5 inches of water is maintained by this control.

There is no auxiliary fuel available in either combustor. Start-up is achieved by feeding waste onto the inclined grate until it is covered, stopping the grate, and igniting the waste. As the flame travels up the inclined grate and becomes more intense, the grate is turned on. Plant personnel indicated that normally it takes 2 to 3 hours to achieve the required operating temperature.

4.1.1.2 Emission Control System Design and Operation. Each combustor is equipped with one spray tower, one evaporation tower and an electrostatic precipitator (ESP). Furnace exhaust gases pass through a section of refractory-lined breeching connecting the combustor to the first of the two cylindrical towers, both of which are 14 feet in outer diameter and approximately 42 feet high.

A spray ring with 14 air atomizing spray nozzles located in the first tower provides up to 200 gpm of city water for quenching the gas. The second tower provides additional residence time for water evaporation and gas cooling. Booster pumps are installed to provide necessary water pressure. The water injection rate is automatically controlled to maintain the ESP inlet temperature at 550°F, as recommended by the ESP manufacturer. A circular chart recorder on the control panel records the ESP inlet temperature, and a strip chart recorder records the actual water flow rate, which is normally about 100 gpm. Excessive ESP inlet temperature will first sound an alarm and then shut down the system induced-draft fan. The bottom of each tower is open to the residue quench pit which removes any large ash particles that accumulate in the tower and maintains the tower pressure seal.

Cooled gases exit the top of the second tower through breeching to the ESP. The precipitators on both combustors are identical 2-field units manufactured by Combustion Engineering and were rebuilt in 1986 according to designs by Research Cottrell. The ESP's are reportedly designed to handle 219,000 acfm at 550°F with 47,000 square feet of collecting plate area; specific collection area (SCA) is 215 ft^2/1,000 acfm. Each ESP vents to a separate stack. Emissions were nearly invisible during the visit (opacity less than 5 percent). A continuous opacity monitor is the only monitoring equipment installed.

Each ESP field is energized by a 1,250 ma, 104 KVA silicon transformer-rectifier and is equipped with instrumentation for monitoring primary voltage, primary current, and secondary current. The instruments are located on the control panel and recorded by the operator hourly. Values noted on one field at the time of the visit were 300 volts AC, 170 amps AC and 1,050 ma DC.

There are also timer controllers located on the panel for activating the rapping system on each field's electrodes. The collection hoppers in both fields are equipped with resistance heaters. Temperature controllers for these heaters are also located on the control panel. There is a single blower which provides preheated air from a resistance heater to the insulators on both fields of the precipitator. An ammeter is located on the panel for monitoring the insulator blower motor current.

Acceptance testing of the rebuilt precipitators showed approximately 97.5 percent collection efficiency with an exit PM concentration of 0.02 gr/dscf. The tests were performed in February 1987 and were conducted according to EPA Method 5.

The fly ash collected in the precipitator is discharged to the same ash quench pit as the bottom ash and the particulate removed in the cooling towers. The combined residue is pulled up a 6-foot drag chain-type inclined conveyor at a speed of 8 feet per minute. Excess water drains back into the quench pit and the residue is discharged from the end of the drag conveyor into waiting trucks (20 cubic yard capacity each). Ash disposal costs are $52.00 per ton. The plant reportedly discharges 200 to 300 gpm of wastewater to the city sewer system.

4.1.2 Description of Model Plant

4.1.2.1 Combustor Design and Operation. Table 4.1-2 presents baseline data for the model plant. For purposes of model development, it was assumed that the model comprises two combustors with operating capacities of 375 tpd of MSW each. As shown in Table 4.0-1, actual unit capacities for combustors in this subcategory range from 225 to 375 tpd.

The original design configuration of the Philadelphia NW incinerators is typical of the existing facilities represented by this model plant. The model consists of a rectangular refractory-lined furnace with two traveling grate sections. Waste is delivered by crane to a water-cooled gravity feed chute which cascades the feed onto an inclined grate. The feed rate is controlled by the speed of the inclined grate. The inclined grate discharge drops vertically approximately 4 1/2 feet onto a horizontal traveling grate where burn out is completed. Bottom ash is discharged from the end of the horizontal finishing grate into a water-filled quench pit. The combustor

TABLE 4.1-2. MODEL PLANT BASELINE DATA

Combustor:
Capacity - 2 units at 375 tons per day each
Grate Area - 480 square feet
Combustor Configuration - Combustors each consist of two connected chambers
Lower Chamber - 55 feet long by 8 feet wide by 21 feet high
Upper Chamber - 21 feet long by 8 feet wide by 13 feet high
Exit Breeching - rectangular, 8 feet by 13 feet
Design Percent Excess Air - 200 percent
Total Excess Air (including inleakage) - 250 percent

Gas Conditioning:
Inlet PM Loading - 3.0 gr/dscf at 7 percent O_2
2 Towers - Diameter 14 feet by height 42 feet (each)
Water Spray - 147 gpm, first tower only

Emission Controls:
Type - 2-field ESP
Gas Flow - 224,000 acfm at 550°F
Collecting Area - 42,500 square feet
SCA - 190 square feet per 1000 acfm
Inlet PM Loading - 0.7 gr/dscf at 7 percent O_2

Stack Emissions:[a]
CDD/CDF (tetra-octa) - 6,000 ng/dscm (1.5E-6 gr/dscf)
CO - 500 ppmv
PM - 0.08 gr/dscf
HCl - 500 ppmv
SO_2 - 200 ppmv
Solid Waste - 187.5 tons per day

Stack Parameters:
Height - 100 feet
Diameter - 8 feet

Operating Data:
Remaining Plant Life - 15 years
Annual Operating Hours - 6,500
Annual Operating Cost - 8,457,000/year

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[a] All values are on a dry, 7 percent O_2 basis. Normal and standard conditions are 1 atmosphere and 70°F.

arrangement is the same as shown in Figure 4.1-1. A plot plan of the model plant is shown in Figure 4.1-2.

There are 4 individual air plenums supplying underfire air to the inclined grate and 6 plenums beneath the horizontal grate. A single forced-draft fan provides underfire and overfire air to each combustor. Overfire air is supplied through 3 rows of nozzles in the combustor roof, similar to the current arrangement at Philadelphia NW. Cooling air is also supplied along the combustor side walls at a level just above the grate. These design features are expected to be fairly typical of other plants in this subcategory.

It is assumed that each of the model units operates at 200 percent excess air. Based on limited measured data available from Philadelphia NW, this may be considered a representative value for plants of this design. An additional 50 percent excess air is assumed to be due to inleakage in the model plant. As discussed in Section 4.1.1.1, this additional air is drawn into the combustor through numerous openings in the furnace walls. This is also considered typical of older refractory-wall combustors. At 250 percent excess air the flue gas flow rate from the combustor is approximately 90,900 scfm (84,300 dscfm). This figure includes the contribution of the flue gas products resulting from combustion of the waste feed.

As stated previously, the upper combustor chamber configuration of the model plant is rectangular and contains no refractory arches or baffles such as those currently in place at Philadelphia NW. There is no source of auxiliary fuel in the model plant. These design assumptions are typical of the majority of plants represented by this model.

4.1.2.2 Emission Control System Design and Operation. As shown in Table 4.0-1, 4 of the 6 plants in this subcategory are equipped with ESP's. The Philadelphia NW plant has recently rebuilt 2-field ESP with particulate matter (PM) emissions of 0.02 gr/dscf adjusted to 12 percent CO_2. The Philadelphia East Central (EC) plant, another member of the mass burn refractory category, has an older 2-field ESP with the same SCA that has the ability to meet the 0.08 gr/dscf PM emission limit. For the model plant, it will be assumed that most existing plants are similar to Philadelphia EC from a particulate control performance standpoint.

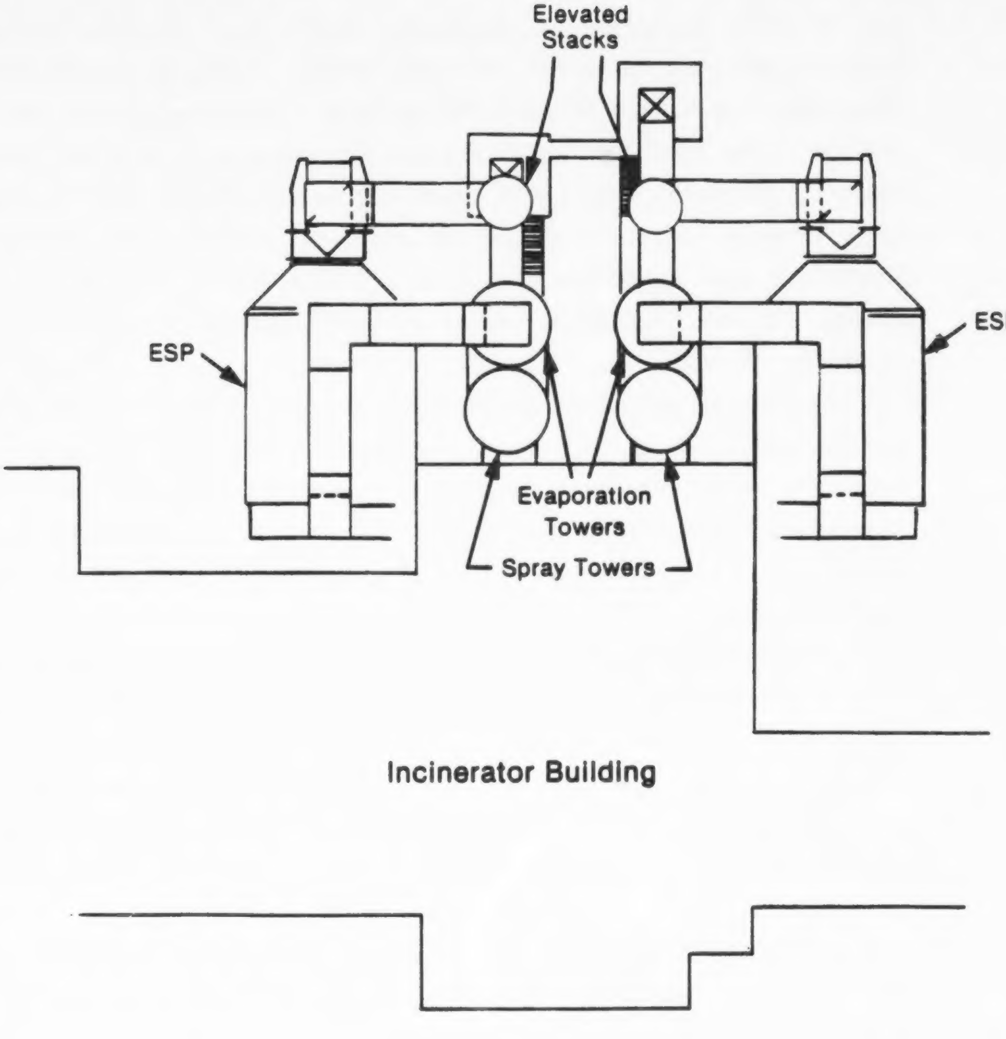

Figure 4.1-2. Plot Plan of Model Plant.

Both of the Philadelphia plants (NW and EC) use water quench systems for flue gas temperature reduction. Use of water sprays is typical for this class of combustors and is assumed for the model plant. It is assumed that the water sprays reduce the temperature of the flue gases to 550°F before they enter the ESP.

4.1.2.3 Environmental Baseline. Table 4.1-2 presents the environmental baseline emission rates for the model plant. Baseline uncontrolled CDD/CDF emissions are assumed to be 4,000 ng/dscm. These levels are due to design and operating practices which are not representative of good combustion. Research indicates that ESP's operating in the 500 to 600°F temperature range promote formation of CDD/CDF and can increase exit concentrations by 50 percent over combustor exit levels.[2] Therefore, the model plant is assumed to have CDD/CDF emissions of 6,000 ng/dscm corrected to 7 percent O_2 at the stack exit.

An average uncontrolled PM emission rate in mass burn waterwall combustors is 2.0 gr/dscf at 12 percent CO^2. Because excess air levels are higher in refractory-wall combustors, a greater amount of particulate matter is assumed to be carried out of the combustor. Therefore, an uncontrolled PM emission rate of 3.0 gr/dscf at 7 percent O_2 is assumed for baseline conditions.

Emissions of CO correlate well with combustion efficiency and have been used in the past as an indicator of CDD/CDF emissions. For the model plant, baseline CO emissions of 500 ppmv are assumed. Baseline uncontrolled HCl and SO_2 emissions are selected to be 500 ppmv and 200 ppmv, respectively.

The model plant reduces incoming waste volumes by 75 percent, and achieves 50 percent weight reduction. At a nominal 375 tons of MSW per day, the bottom ash (dry) is estimated to be 187.5 tons/day. It is assumed that the bottom ash and fly ash are mixed and co-disposed, as is the practice at Philadelphia. Generally, fly ash accounts for about 5 percent of the total ash.

4.1.3 Good Combustion and Exhaust Gas Temperature Control

The following sections outline retrofits necessary to insure good combustion at the model plant described above.

4.1.3.1 Description of Modifications

Design Modifications

Grate Replacement. Each unit is equipped with two traveling stokers which move the waste feed through the combustor. Traveling grates in mass burn systems do not provide agitation and subsequent aeration of the fuel bed in the manner that rocking or reciprocating grates do. Traveling grates, therefore, are less able to provide good fuel bed burnout, particularly if specified grate loading rates are not carefully maintained.

Excessive bed loadings contribute to high concentrations of organic emissions. Retrofits necessary to insure good combustion and minimum levels of air emissions are:

1) replace the traveling grate system with reciprocating grate sections that are equipped with individually controllable underfire air supplies.
2) add a ram feeder to establish good feed control.

Grate replacement requires extensive demolition and some redesign of the existing structural steel and refractory brickwork. The new design includes 3 grate sections per furnace, each supplied by 2 separate underfire air plenums. Each of the 6 plenums is equipped with an individual damper and pressure monitor/recorder. New siftings and ash hoppers and a new ash conveyor are also required as part of this modification. It is assumed that a new ram feeder is included as part of grate replacement for each unit.

In addition to improving waste burnout and reducing solids disposal requirements, this retrofit will result in better control of feed rates, fuel bed distribution, supply of underfire air, and location of burning patterns on the grate. These improvements will help to optimize destruction of organic compounds in the combustor and will also reduce CO emission levels.

Furnace Reconfiguration. The baseline configuration of the model plant is not adequate to achieve good combustion. A conceptual redesign of the model is provided in Figure 4.1-3. The reconfiguration includes a refractory-lined structural steel arch which is located on the rear wall of the furnace. In addition, the roof of the upper combustion chamber has been raised in order to increase the available volume for completing the mixing

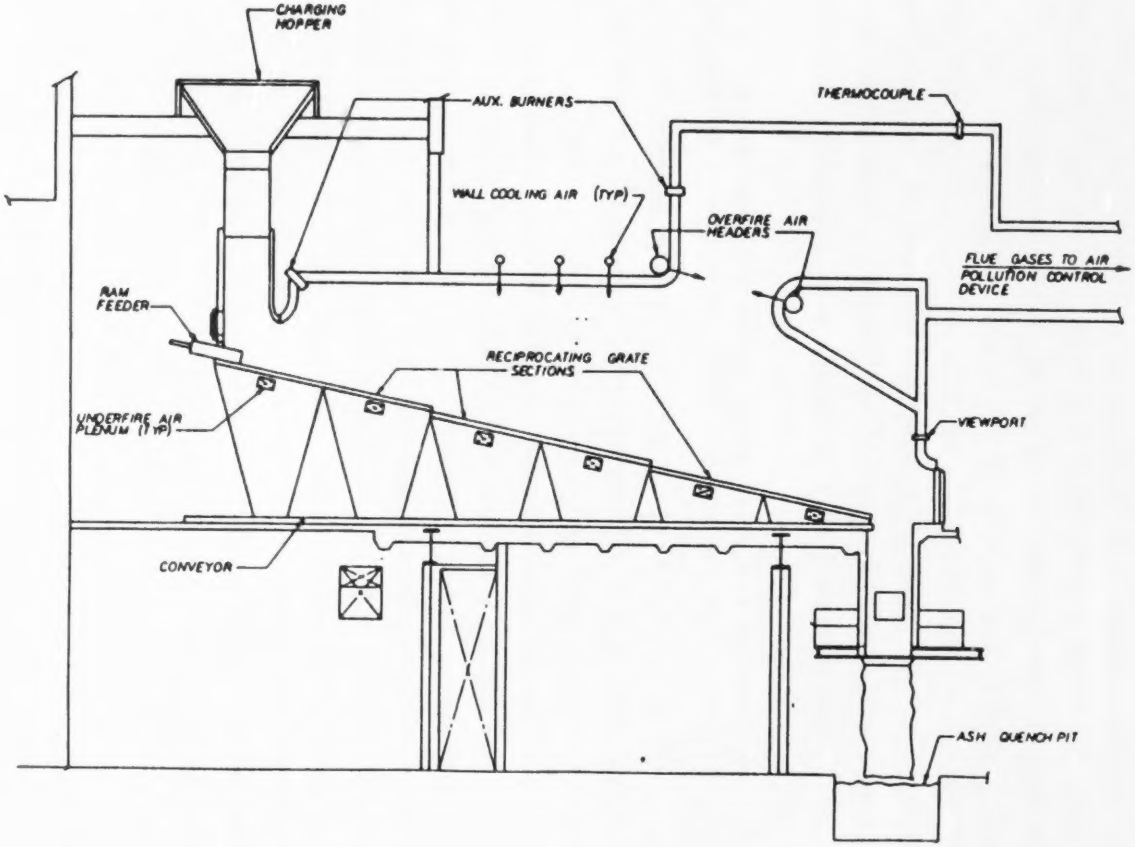

Figure 4.1-3. Model Plant Combustor Profile Showing Combustion Retrofits

process. This retrofit requires partial demolition of the existing furnace walls and roof, and construction of a new furnace shell and refractory brickwork.

Combustion Airflow Modifications

The following design and operational modifications must be made to the model plant's combustion air system.

- Excess air operating levels will be reduced from 200 to 150 percent excess air. This modification has a number of beneficial effects on system performance. First, furnace operating temperatures can be maintained at higher levels (approximately 1800°F at the fully mixed location). Secondly, lower excess air levels reduce the potential for particulate carryover by lowering vertical velocities in the upper furnace. Lastly, reduced excess air levels increase the SCA of existing electrostatic precipitators, resulting in improved particulate removal. At 150 percent excess air, total gas flow from the combustor will be reduced to 61,700 scfm (57,900 dscfm) per unit.

- Each of the three new grates has two independently controllable air plenums with individual supply dampers, ducting, and pressure monitors. Approximately 125 percent theoretical air (50 percent of total air) is supplied to the six underfire plenums. The underfire air distribution is established as a result of operational performance tests. The underfire air supply to the drying grate also includes a natural gas burner which can be fired as needed for air preheat when feeding wet refuse.

- New overfire air headers, nozzles, dampers, ducting, and pressure monitors are installed to provide a source of air for mixing. Two rows of interlaced nozzles are required, as shown in Figure 4.1-3. Flow modeling studies will be used to establish nozzle sizes, orientation, spacing, etc. In-furnace CO profiling will be used to provide verification of mixing patterns. The quantity of air supplied through the overfire mixing nozzles is approximately 75 percent theoretical air, or 30 percent of total air.

- The existing overfire air nozzles, comprising three rows on the furnace ceiling, are retained for use as cooling air. Approximately 50 percent of theoretical air (20 percent of total air) is supplied by these existing rows. New header pressure monitors are required as part of the system retrofit.

- The last improvement to the combustion air system is the elimination of air inleakage as a result of the grate replacement and furnace reconfiguration. This results in greater operational stability, which contributes to lower air emissions.

Auxiliary Fuel. The modified model plant has two auxiliary fuel burners sized to provide 60 percent of unit full load (84.4 MM Btu) for use during process start-up and during episodes of low temperature and high CO. The first burner is located at the head of the primary combustion chamber above the drying grate, and it is used to ignite the waste and maintain primary combustion chamber temperature during start-up. A second gas burner is located in the upper chamber just downstream of the mixing air nozzles. Location of the burner in the upper chamber helps achieve the requirement of 1800^{0}F at the fully mixed height during start-up, shutdown, and other episodes of high CO or low temperature. The upper auxiliary fuel burner also preheats and maintains the temperature of the flue gas cleaning equipment prior to initiating waste feeding and during shutdown. This minimizes corrosion problems, thus improving system environmental and operational performance. The optimum location and orientation of the burners in the modified model will be established by flow modeling.

Operation/Control Modifications

Minimize Residence Time at Critical Temperature. The goal of this operational modification is to minimize the effects of downstream CDD/CDF formation by minimizing the residence time of flue gases in the 500 to 600^{0}F range, where research indicates that CDD/CDF formation is maximized. The model plant normally operates the water quench system at a flow rate that maintains a temperature of 550^{0}F in the ESP. This operating practice must be modified in order to lower the ESP temperature below the critical temperature window. The modification requires an adjustment to the set point on the ESP temperature controller to increase the quench water flow rate and reduce the ESP temperature to 450^{0}F. This temperature provides an ample factor of safety in avoiding acid gas dew point problems.

Combustion Control. In the baseline configuration the combustion control scheme is entirely manual. As part of the combustion modifications improved controls are necessary. Because there is no steam production, the primary variables to include in the control scheme are excess oxygen and temperature. The revised controls include an oxygen trim loop which automatically adjusts the amount and distribution of underfire air in response to a signal from an oxygen controller. A temperature controller is included with an alarm at high and low setpoints. Overfire air rates are kept constant. Adjustments in overfire air and grate speed will be made manually, if needed.

Verification. Verification of good combustion consists of insuring that the system is operating according to its design. There are a number of operating parameters that must be monitored and controlled in order to achieve this objective. At a minimum, refractory-wall combustors must continuously monitor:

1) underfire and overfire air flows (pressure settings)
2) combustor draft
3) O_2 (excess air) and CO in the flue gas
4) combustor temperature.

Underfire and overfire airflows are monitored by maintaining specified pressures in supply headers. Combustor draft is maintained by a variable-speed ID fan. Flue gas O_2 and CO measurements must be at the same location in the system so that the CO reading can be corrected to a standard value, such as 7 percent O_2. Combustor temperature requirements are specified at a location where the mixing process is completed, just downstream of the last point of overfire air injection.

Retrofit Considerations. It is estimated that the combustor downtime required to implement all of the combustion retrofit options is approximately 4 months per unit.

4.1.3.2 Environmental Performance. The combustion retrofits address the design, operation/control, and verification requirements for good combustion for mass burn refractory-wall combustors represented by this model plant. Through the proper application of the above combustion retrofit options, it is estimated that uncontrolled emissions of CDD/CDF will be reduced to 500 ng/dscm corrected to 7 percent O_2.[2] In addition, emissions of CO are estimated to be reduced to 150 ppm on a 4-hour averaging time. No change in uncontrolled particulate emissions is expected. Emissions of HCl and SO_2, because they are related to feed properties, are also not expected to vary due to combustion modifications.

4.1.3.3 Costs. This section provides estimates of total capital and annual operating and maintenance (O&M) costs for identical combustion retrofits to both combustion units. Capital costs represent the installed equipment costs, including engineering and construction. Direct and indirect capital costs are summarized in Table 4.1-3. Operating and maintenance costs include all utilities, labor, and ash disposal costs. These estimated costs are presented in Table 4.1-4.

The total estimated capital cost of the combustion retrofits is $11,900,000. Downtime cost, resulting from lost revenue, is $846,000. The annualized capital and downtime cost is $1,680,000 per year, based on a 10 percent interest rate and 15-year plant life. Total annualized cost is $1,330,000, including a cost saving of $1,220,000 for reduced ash disposal costs.

4.1.4 Good Particulate Control

The existing quench towers reduce baseline PM loadings from 3.0 gr/dscf at the combustor outlet to 0.7 gr/dscf at the outlet of the quench towers. The existing ESP's reduce PM loadings from 0.7 gr/dscf at the ESP inlet to 0.08 gr/dscf at the outlet. This level is equal to the 0.08 gr/dscf required by the existing NSPS for PM emissions from MWC's.

4.1.4.1 Description of Modifications. To reduce PM emissions to 0.05 gr/dscf, the existing ESP's have to be rebuilt. This rebuild will include replacing worn or damaged internal components (plates, frame and electrodes), upgrading of controls and electronics for more effective energization, and flow modeling to evaluate gas distribution. Even gas distribution minimizes particulate reintrainment and equalizes particulate collection across the width and height of the ESP. These modifications do not include major changes such as additional collection area or plate-electrode geometry changes.

Space is sufficient to allow ESP-rebuild work on one unit without hindering operation of the adjacent unit. Approximately 2 months downtime will be required for each unit.

4.1.4.2 Environmental Performance. Particulate matter emissions will be reduced from baseline levels of 0.08 gr/dscf to 0.05 gr/dscf. This additional fly ash recovery will add 60 tons/year to the plant solid waste

TABLE 4.1-3. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 375 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Flow Modeling and Thermal Analysis	125
Overfire Air Ducting and Dampers	34
Gas Pipeline (1/2 mile)	50
Auxiliary Fuel Burners	203
Stokers Rehabilitation	2,800
Underfire and Overfire Airflow Monitors	33
Oxygen and CO Monitors with Readouts and Integrators	90
CO Profiling	10
Air Preheat	4
Oxygen Trim Controls on FD Fan	25
Furnace Reconfiguration	4,080
Total	7,460
INDIRECT COSTS AND CONTINGENCIES:	4,470
TOTAL CAPITAL COSTS	11,900
DOWNTIME COST	846
ANNUALIZED CAPITAL COST AND DOWNTIME	1,680

TABLE 4.1-4. PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 375 tpd each)

Item		Cost ($1000)
DIRECT COSTS:		
Auxiliary Gas Consumption		316
Ash Disposal Costs		(1,220)[a]
Water		7
Maintenance Labor		21
Maintenance Materials		21
Operating Labor		0
	Total	(854)[a]
INDIRECT COSTS:		
Overhead		25
Taxes, Insurance, Administrative		477
Capital Recovery and Downtime		1,680
	Total	2,180
TOTAL ANNUALIZED COST		1,330

[a] Denotes cost savings.

disposal requirements. This increase is roughly 0.1 percent of the existing disposal quantity. Emissions of CDD/CDF and acid gases are assumed to not be affected by this modification.

4.1.4.3 Costs. Capital cost requirements for ESP rebuild for both units are presented in Table 4.1-5. Total capital cost is estimated to be $962,000. This figure includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion level, no additional general facilities, and no purchased land. Downtime cost is $423,000 for lost revenue.

Annual costs are presented in Table 4.1-6. Direct O&M costs are estimated at $2,000 per year. Annualized capital recovery and downtime based on a 10 percent interest and 15-year life is $182,000 per year. Total annualized costs are $184,000 per year.

4.1.5 Best Particulate Control

4.1.5.1 Description of Modifications. To achieve PM emissions level of 0.01 gr/dscf with an inlet grain loading of 0.7 gr/dscf will require a well-operated ESP with 56,200 square feet of collection for each combustor. To achieve this performance, each existing ESP will be rebuilt and a second ESP with 13,700 square feet of plate area will be installed in series at the outlet of each existing ESP. Rebuild of the existing ESP's will include replacing worn components, upgrading controls, and flow modeling. As shown in Figure 4.1-4, installation of each new ESP will require relocation of an ID fan and 75 feet of new ducting to an existing stack. Most of the construction of the new ESP's can be accomplished without disrupting operation. Downtime for rebuild of the existing ESP's and tie-in of the new units will be approximately 2 months for each unit.

4.1.5.2 Environmental Performance. Particulate matter emissions will be reduced from 0.08 gr/dscf to 0.01 gr/dscf. The additional recovered fly ash will add roughly 140 tons/yr to total solid waste disposal requirements. This is a 0.2 percent increase in fly ash to disposal. Emissions of CDD/CDF and acid gases are assumed to not be affected by this modification.

4.1.5.3 Costs. Capital cost requirements for the new ESP, presented in Table 4.1-5, are estimated to be $3,280,000. This includes purchased equipment, installation, and indirect costs such as engineering and

TABLE 4.1-5. CAPITAL COST OF PARTICULATE MATTER CONTROL UPGRADES (Two units of 375 tpd each)

Item	Costs ($1000) Good Particulate Control (ESP Rebuild Only)	Costs ($1000) Best Particulate Control (ESP Rebuild and Additional Plate Area)
DIRECT COSTS:		
PM Control		
Upgrade Costs	800	2,190
Access/Congestion Cost	NA[a]	346
New Flue Gas Ducting		
Ducting Costs	NA	95
Access/Congestion Cost	NA	24
Other Equipment		
Stacks	NA	0
Demolition/Relocation	NA	0
Total	800	2,650
Indirect Costs and Contingencies	162	631
Monitoring Equipment[b]	0	0
TOTAL CAPITAL COST	962	3,280
DOWNTIME COST	423	423
ANNUALIZED CAPITAL RECOVERY	182	487

[a] NA = not applicable.

[b] Turnkey.

TABLE 4.1-6. PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROL UPGRADES (Two units of 375 tpd)

Item	Cost ($1000)	
	Good Particulate Control (ESP Rebuild Only)	Best Particulate Control (ESP Rebuild and and Additional Plate Area)
DIRECT COSTS:		
Operating Labor	0	0
Supervision	0	0
Maintenance Labor	0	0
Maintenance Materials	0	25
Electricity	0	11
Waste Disposal	2	5
Monitors	0	0
Total	2	41
INDIRECT COSTS:		
Overhead	0	15
Taxes, Insurance, and Administration	0	99
Capital Recovery and Downtime	182	487
Total	182	601
TOTAL ANNUALIZED COST	184	642

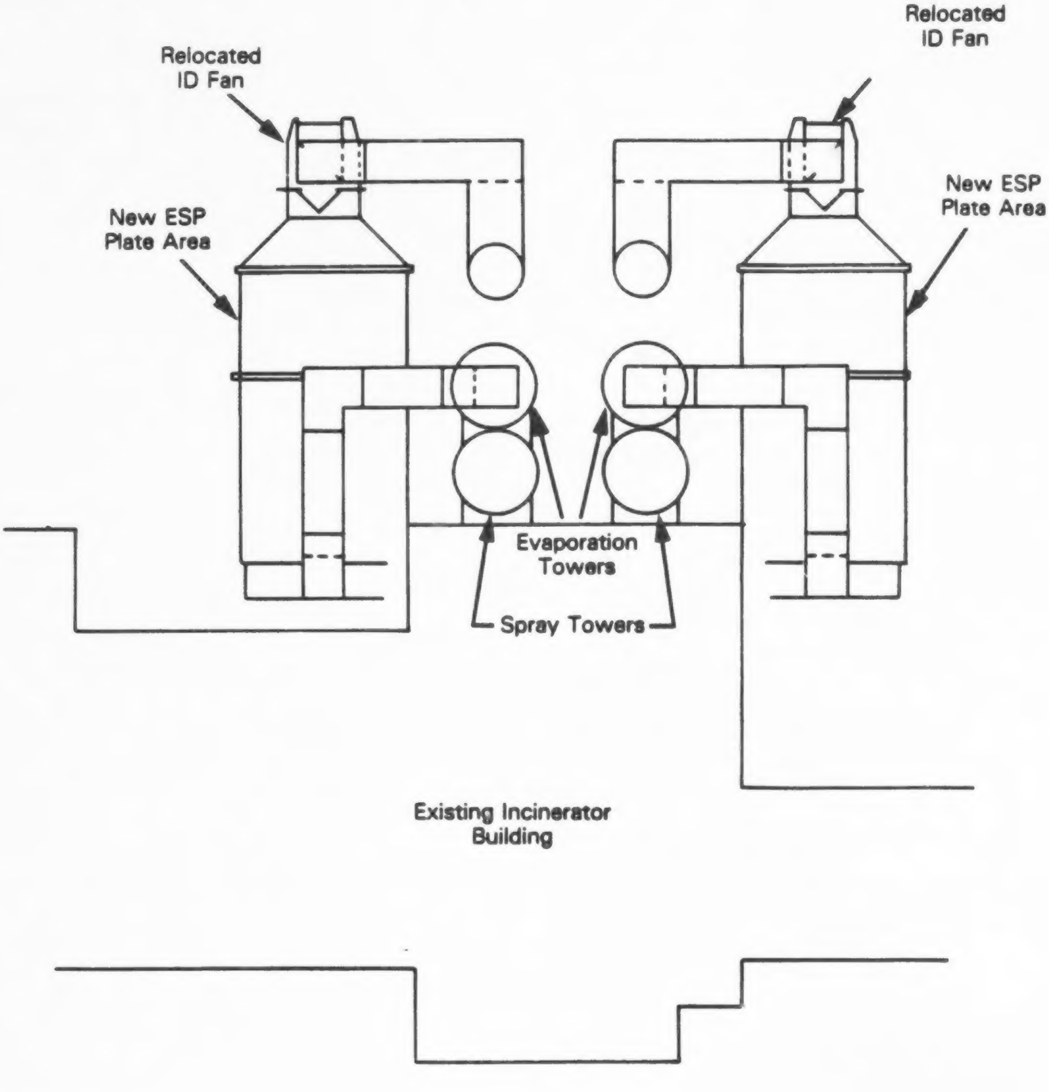

Figure 4.1-4. Plot Plan of New ESP Plate Area Equipment Arrangement

contingencies. Estimates assume a moderate APCD congestion factors, 150 feet of additional duct, no additional general facilities, and no purchased land.

Annual costs are presented in Table 4.1-6. Direct O&M costs are estimated at $41,000 per year. Total annualized costs including capital recovery are estimated at $642,000 per year.

4.1.6 Good Acid Gas Control

4.1.6.1 Description of Modifications. For good acid gas control and good CDD/CDF control on on each combustor, dry sorbent will be injected into the existing evaporation chamber (i.e., the second tower). The water quench system on the existing spray chamber (i.e., the first tower) will remain in place. An additional 25 gpm will be used to cool the flue gas to 350^{0}F from 450^{0}F, if good combustion practices are in place; 35 gpm will be required under baseline combustion conditions to cool from 550^{0}F. New equipment for the site includes a single sorbent storage silo, a pneumatic sorbent conveying system, two sorbent feed bins (one for each unit), and pneumatic injection nozzles for each evaporation chamber. No other modifications to the evaporation chamber will be required. Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full load, this requires a sorbent injection rate of 425 lb/hr for each combustor.

In addition, the existing ESP's will be rebuilt and new plate area added to reduce PM emissions to 0.01 gr/dscf. The rebuild will include replacing worn components, upgrading controls and flow modeling, but no major geometry changes. An additional 49,000 square feet of ESP plate area will be added to each ESP under baseline combustion conditions and 30,200 square feet under good combustion. The area will be installed using a separate ESP located in series behind each existing ESP. The project also includes monitoring equipment for HCl, SO_2, CO_2, and O_2. Figure 4.1-5 shows a plot plan of the equipment arrangement.

There are no access/congestion problems related to the evaporation chamber modifications; the lime receiving, storage, and conveying equipment installation; or the particulate control upgrade installation. Installation of each new ESP will require relocation of an ID fan and 75 feet of new

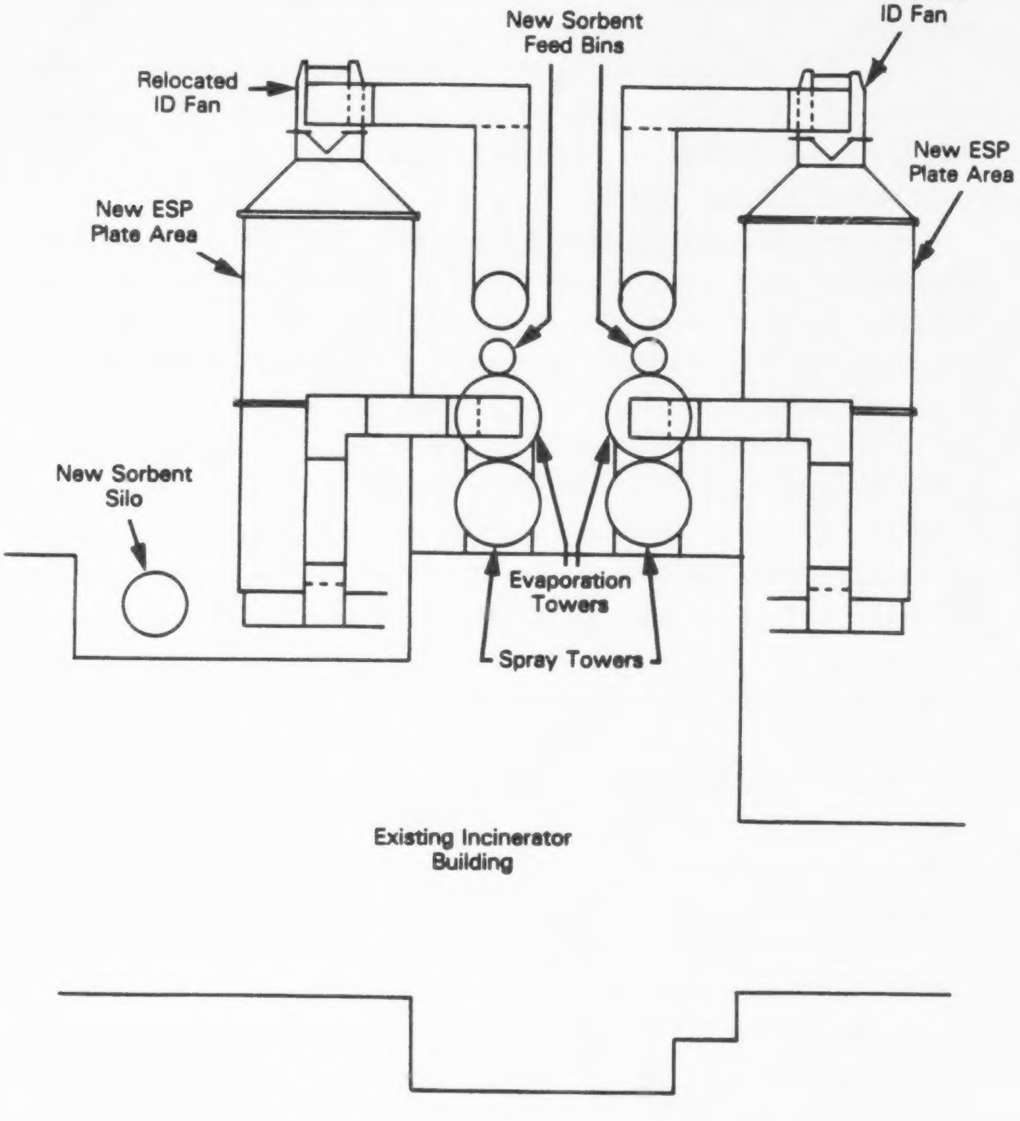

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Figure 4.1-5. Plot Plan of Dry Sorbent Injection Retrofit Equipment Arrangement.

ducting to an existing stack, but can be accomplished with the adjacent combustor still operating. Advanced planning will be required to limit combustor downtime to approximately 2 months for each unit.

4.1.6.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 75 percent from inlet levels or to 50 ng/dscm (whichever is higher). Acid gas emission reductions are estimated at 80 percent for HCl and 40 percent for SO_2, respectively. As noted above, PM emissions will be reduced to 0.01 gr/dscf. An additional 3,700 tons/year of solid waste (sorbent and fly ash) will be added to the baseline waste disposal requirements for the plant.

4.1.6.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 4.1-7. Total capital cost for the plant is estimated at $6,750,000 with baseline combustion and $5,770,000 with good combustion. Most of the cost is associated with installation of additional particulate control equipment. The cost estimate assumes a moderate APCD access/congestion level, few additional general facilities, and no purchased land.

Annual O&M and indirect costs are presented in Table 4.1-8. Major direct operating costs are associated with lime purchase and monitoring equipment maintenance. The total annualized cost for the control option (including capital recovery and downtime) is $1,960,000 per year with baseline combustion and $1,750,000 per year with good combustion.

4.1.7 Best Acid Gas Control

4.1.7.1 Description of Modifications. To achieve best acid gas and CDD/CDF control, a new spray dryer/fabric filter system will be installed on each combustor after the spray tower. The existing evaporation towers will be removed to make room for the spray dryer vessels. Lime slurry will be introduced in each spray dryer at a 2.5:1 calcium-to-acid gas molar ratio. Lime will be slurried in the additional water (43 gpm) needed to cool the flue gas to 300°F from 550°F under baseline combustion, or in the 18 gpm required under good combustion. The proposed equipment layout is illustrated in Figure 4.1-6.

This sketch also shows the location of the lime receiving, storage, and slurry area which will serve both spray dryers. A fabric filter with 59,800 square feet of cloth (net air-to-cloth ratio of 4:1) will be installed

TABLE 4.1-7. CAPITAL COST OF DRY SORBENT INJECTION WITH REBUILD OF EXISTING ESP AND ADDITION OF ESP PLATE AREA
(Two units of 375 tpd each)

Item		Costs ($1000)	
		Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:			
Acid Gas Control			
Equipment		394	394
Access/Congestion Cost		39	39
Particulate Control			
Equipment		3,330	2,750
Access/Congestion Cost		632	489
New Flue Gas Ducting			
Ducting Cost		102	90
Access/Congestion Cost		25	23
Other Equipment			
Stacks		0	0
Demolition/relocation		0	0
	Total	4,520	3,790
Indirect Costs & Contingencies		1,720	1,470
Monitoring Equipment[a]		514	514
TOTAL CAPITAL COST		6,750	5,770
DOWNTIME COST		423	423
ANNUALIZED CAPITAL RECOVERY		944	815

[a] Turnkey.

TABLE 4.1-8. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH REBUILD OF EXISTING ESP AND ADDITION OF ESP PLATE AREA
(Two units of 375 tpd each)

Item	Cost ($1000) Baseline Combustion Practices	 Good Combustion Practices
DIRECT COSTS:		
Operating Labor	39	39
Supervision	12	12
Maintenance Labor	11	11
Maintenance Materials	66	56
Electricity	65	47
Water	14	5
Lime	221	221
Waste Disposal	92	92
Monitors	206	206
Total	726	689
INDIRECT COSTS:		
Overhead	76	71
Taxes, Insurance, and Administration	211	172
Capital Recovery and Downtime	944	815
Total	1,230	1,060
TOTAL ANNUALIZED COST	1,960	1,750

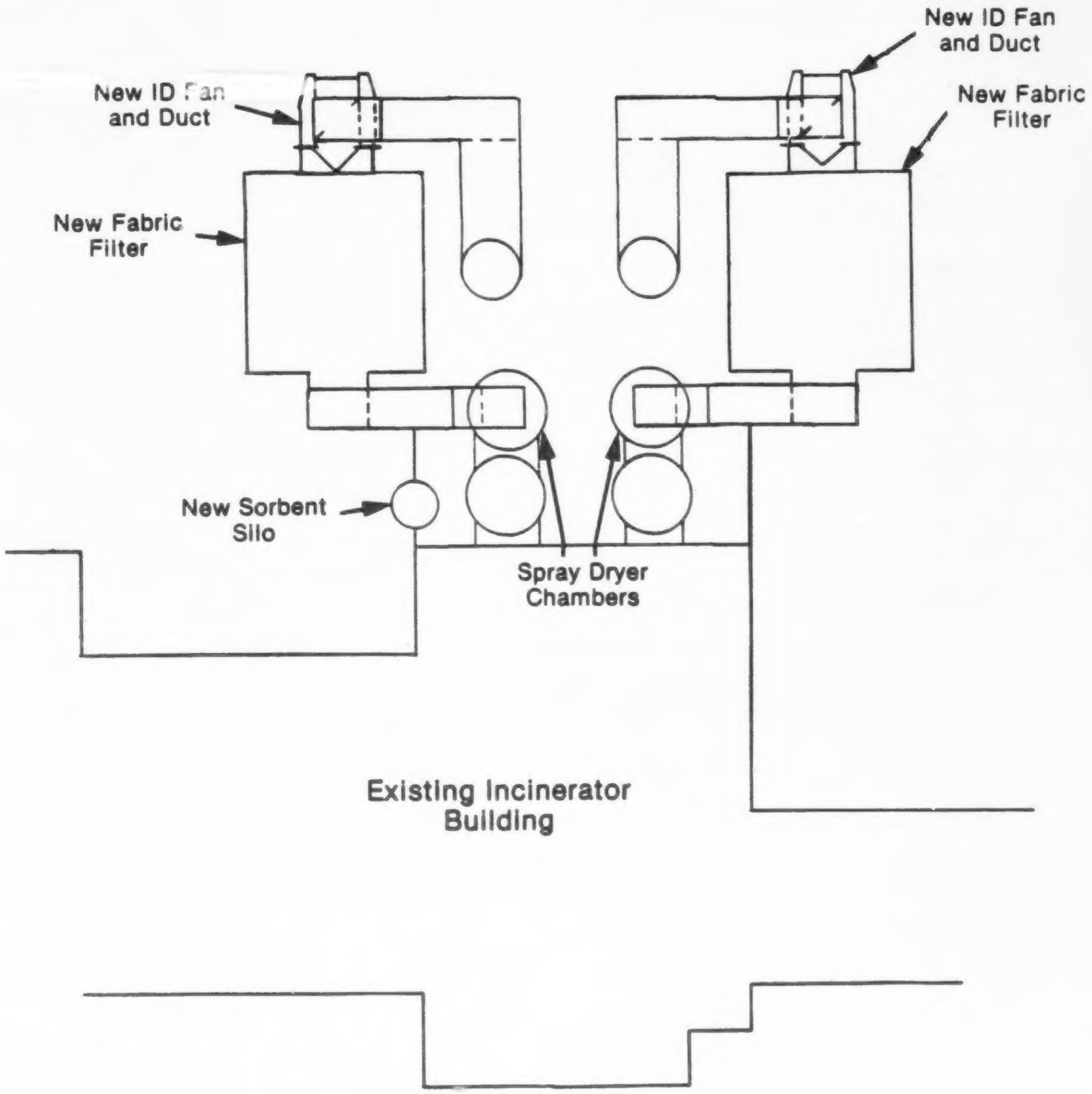

Figure 4.1-6. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement.

following each spray dryer under baseline combustion; with good combustion, 47,800 square feet will be needed. The existing ESP's and evaporation chambers will be demolished to make room for the new fabric filters. The increased pressure drop of fabric filters over ESP's will require a new ID fan for each unit as well. An estimated 200 total feet of new duct will be needed, but the existing stacks can be reused. New monitoring instruments for HCl, SO_2, CO_2, and opacity will be installed. Downtime is expected to be 3 months.

4.1.7.2 Environmental Performance. Total CDD/CDF emission reductions of 99 percent or to 5 ng/dscm (whichever is higher) are expected. Emissions of PM will be reduced from 0.08 gr/dscf to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl.

4.1.7.3 Costs. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 4.1-9. Total capital cost is estimated to be $23,900,000 for installation with baseline combustion or $21,400,000 for installation with good combustion. This figure includes purchased equipment, installation, demolition, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion (since much of the equipment will be elevated), few additional general facilities, and no purchased land. Downtime cost for 3 months lost revenue is $634,000.

Annual O&M and indirect costs are presented in Table 4.1-10. Significant O&M expenses include replacement bags for the fabric filter and electricity for the larger ID fan needed due to the increased pressure drop across the fabric filters. Total annualized cost, including capital recovery and downtime is $5,920,000 with baseline combustion and $5,310,000 with good combustion practices.

4.1.8 Summary of Control Options

4.1.8.1 Description of Control Options. The control technolcgies described in the previous sections have been combined into the seven retrofit emission control options that were discussed in detail in Section 3.0. Table 4.1-11 summarizes the combustion, particulate, temperature, and acid gas control technologies described in Sections 4.1.3 through 4.1.7 that were combined for each of the control options.

TABLE 4.1-9. CAPITAL COST OF SPRAY DRYER WITH FABRIC FILTER (Two units of 375 tpd each)

Item		Cost ($1000)	
		Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:			
Acid Gas Control			
Equipment		10,500	9,410
Access/Congestion Cost		2,630	2,350
New Flue Gas Ducting			
Ducting Cost		146	131
Access/Congestion Cost		37	33
Other Equipment			
Fans		793	644
Stacks		0	0
Demolition/Relocation		750	750
	Total	14,900	13,300
Indirect Costs		4,670	4,150
Contingency		3,760	3,350
Monitoring Equipment[a]		573	573
TOTAL CAPITAL COSTS		23,900	21,400
DOWNTIME COST		635	635
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		3,230	2,900

[a] Turnkey.

TABLE 4.1-10. ANNUAL COST OF SPRAY DRYER WITH FABRIC FILTER
(Two units of 375 tpd each)

Item	Cost ($1000) Baseline Combustion Practices	Cost ($1000) Good Combustion Practices
DIRECT COSTS:		
Operating Labor	78	78
Supervision	12	12
Maintenance and Labor	43	43
Maintenance Materials	399[a]	344[b]
Electricity	415	329
Compressed Air	59	47
Water	17	12
Lime	183	182
Waste Disposal	121	120
Monitors	215	215
Total	1,540	1,380
INDIRECT COSTS:		
Overhead	249	230
Taxes, Insurance, and Administration	903	803
Capital Recovery and Downtime	3,230	2,900
Total	4,380	3,930
TOTAL ANNUALIZED COST	5,920	5,310

[a] Includes $116,000 per year for bag replacement.

[b] Includes $93,000 per year for bag replacement.

TABLE 4.1-11. SUMMARY OF CONTROL OPTIONS FOR TRAVELING GRATE MASS BURN REFRACTORY-WALL COMBUSTOR

			Particulate Matter Control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion and Temperature Control	X	X	X				
3. Best PM Control and Combustion and Temperature Control	X	X	X	X			
4. Good Acid Gas Control, Best PM Control and Temperature		X	X	X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control Control	X	X	X	X		X	
6. Best Acid Gas Control, Best PM Control and Temperature Control		X			X	X	
7. Best Acid Gas Control, and Best PM/Combustion/ Temperature Control	X	X			X	X	

4.1.8.2 Environmental Performance. The performance of each control option is summarized in Table 4.1-12. For each pollutant the table presents both the pollutant concentrations and annual emissions. The most effective retrofit option for controlling CDD/CDF emissions is addition of spray dryer/fabric filter systems which reduce emissions by 99 percent from inlet levels. Good combustion practices are nearly as effective in controlling CDD/CDF, and produce emission reductions of 90 percent. Sorbent addition technology (including dry sorbent injection) also reduces acid gas emissions, but good combustion practices reduce CO. The best overall control results from combining combustion control and sorbent addition as in Options 5 and 7.

4.1.8.3 Costs. The total annualized cost of each option is presented in Table 4.1-13. Total annualized cost of each option increases with increasing control, though good combustion costs are partially offset by lower solid waste disposal costs resulting from more complete waste burnout The most cost-effective option is Option 4, which provides most of the potential emission control (except CO reduction) at a cost of $1,960,000 per year (annualized total cost).

4.1.8.4 Energy Impacts. Table 4.1-14 presents a summary of the energy impacts associated with the control options. The values presented are incremental energy use relative to baseline operation, and take into account the savings realized by not operating the existing ESP's under Options 6 and 7. Note that there is a considerable electrical penalty for the higher (baseline) gas flow rates in Options 4 and 6.

TABLE 4.1-12. ENVIRONMENTAL PERFORMANCE OF SUMMARY FOR MASS BURN TRAVELING GRATE REFRACTORY-WALL MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 375 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Dioxin Emissions								
(ng/dscm)	6,000	500	500	500	1000	125	40	5
Mg/yr	4.7E-3	2.0E-4	3.9E-4	3.9E-4	3.3E-4	9.9E-5	3.3E-5	3.9E-6
% Reduction vs. Baseline	--	92	92	92	83	98	99.3	99.9
CO Emissions								
(ppmv)	500	150	150	150	500	150	500	150
Mg/yr	494	148	148	148	494	148	494	148
% Reduction vs. Baseline	--	70	70	70	0	70	0	70
PM Emissions								
(gr/dscf)	0.08	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	146	91	91	18	18	18	18	18
% Reduction vs. Baseline	--	38	38	88	88	88	88	88
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	452	452	452	452	272	272	42	42
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	643	643	643	643	128	128	18	18
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	396	188	188	184	389	201	393	205
Mg/yr	92,300	46,300	46,300	46,500	95,800	49,500	96,700	50,500
% Reduction vs. Baseline[b]	--	(50)	(50)	(49)	4	(46)	5	(45)

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Normal and standard conditions are 1 atmosphere and 70°F.

[b] Decrease vs. baseline shown in parentheses.

TABLE 4.1-13. COST SUMMARY FOR MASS BURN TRAVELING GRATE REFRACTORY-WALL COMBUSTOR RETROFIT CONTROL OPTIONS[a] (Two units of 375 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	11,900	12,900	15,200	6,750	17,700	23,900	33,300
Downtime Cost	846	846	846	423	846	635	846
Annualized Capital and Downtime Cost	1,680	1,810	2,110	944	2,440	3,230	4,490
Direct O&M Cost	(854)[b]	(852)[b]	(813)[b]	726	(165)[b]	1,540	526
Total Annual Cost	1,330	1,460	1,920	1,960	3,020	5,920	6,560
Cost Effectiveness ($/ton MSW)	6.55	7.19	9.45	9.65	14.90	29.10	32.30
Facility Downtime (Months)	4	4	4	2	4	3	4
Total Compliance Time (Months)	11	13	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

[b] Denotes cost savings.

TABLE 4.1-14 TOTAL PLANT ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	2.0E10
2	0	2.0E10
3	230	2.0E10
4	1,360	0
5	1,000	2.0E10
6	9,030[b]	0
7	7,150[b]	2.0E10

[a] Incremental use from baseline.

[b] Excludes electrical credit for not operating the ESP's.

4.2 ROCKING/RECIPROCATING GRATE MASS BURN REFRACTORY-WALL COMBUSTOR

This section presents the case study results for a refractory-wall combustor equipped with rocking/reciprocating grates. As shown in Table 4.0-1, there are 11 known plants in this subcategory. Section 4.2.1 presents a description of the Sheboygan MWC plant, which was visited in order to gather information for model development. Section 4.2.2 presents a description of the model plant. Sections 4.2.3 through 4.2.7 detail the retrofit modifications, estimated performance, and costs associated with various control options. Section 4.2.8 presents a summary of the control options, which are discussed in more detail in Section 3.0 of this report.

4.2.1 Description of the Sheboygan, Wisconsin Combustor[3]

The Sheboygan MWC plant, which began operation in 1964, consists of two rectangular refractory-wall combustors with individual firing capacities of 120 tpd of MSW. The stokers were manufactured by Flynn and Emrich, and utilize three rocking grate sections per combustor. Table 4.2-1 summarizes key design and operating data for the plant. The plant operates 4 to 5 days/week with scheduled maintenance every Monday. Reported operating capacities are 4 to 5 tons/hr per combustor. The plant employs 15 people and operates 24-hr/day. In addition to burning MSW the plant also burns skimmings from the sewage treatment plant. A total of 417 tons of sludge were burned in 1986.

4.2.1.1 Combustor Design and Operation. Figure 4.2-1 illustrates the cross-section of the combustors at the Sheboygan plant. Waste is charged from a holding pit into a water-cooled hopper which feeds each combustor by gravity. The feed rate is controlled by varying the speed of the first (drying) grate section, which is 8 feet in length and 7 feet wide. The majority of the burning takes place on the second grate section, and burnout is completed on the third (finishing) grate. There are 1-foot vertical steps between each of the three grates, allowing the waste to tumble from one section to another. The second and third grate sections are 10 feet in length. Bottom ash is discharged from the finishing grate to a wet quench. A drag chain conveyor transports the ash to a truck for disposal in a nearby landfill.

TABLE 4.2-1. SHEBOYGAN DESIGN DATA[a]

Combustor:	
Capacity	- 120 tpd
Total Grate Area	- 202 square feet
First Grate	- 7 feet wide by 8 feet long, 15° incline
Second Grate	- 7 feet wide by 10 feet long, 15° incline
Third Grate	- 7 feet wide by 10 feet long, 15° incline
Overall Combustor Dimensions	- 28 feet long by 7 feet wide by 18 feet high
Exit Breeching	- Rectangular, 7 feet by 7 feet
Emission Controls:	
Baffle Chambers	- 37 feet long by 7 feet wide by 18 feet high
Spray Nozzles	- 21 full-cone nozzles in first spray section, 21 flat-spray nozzles in second spray section.

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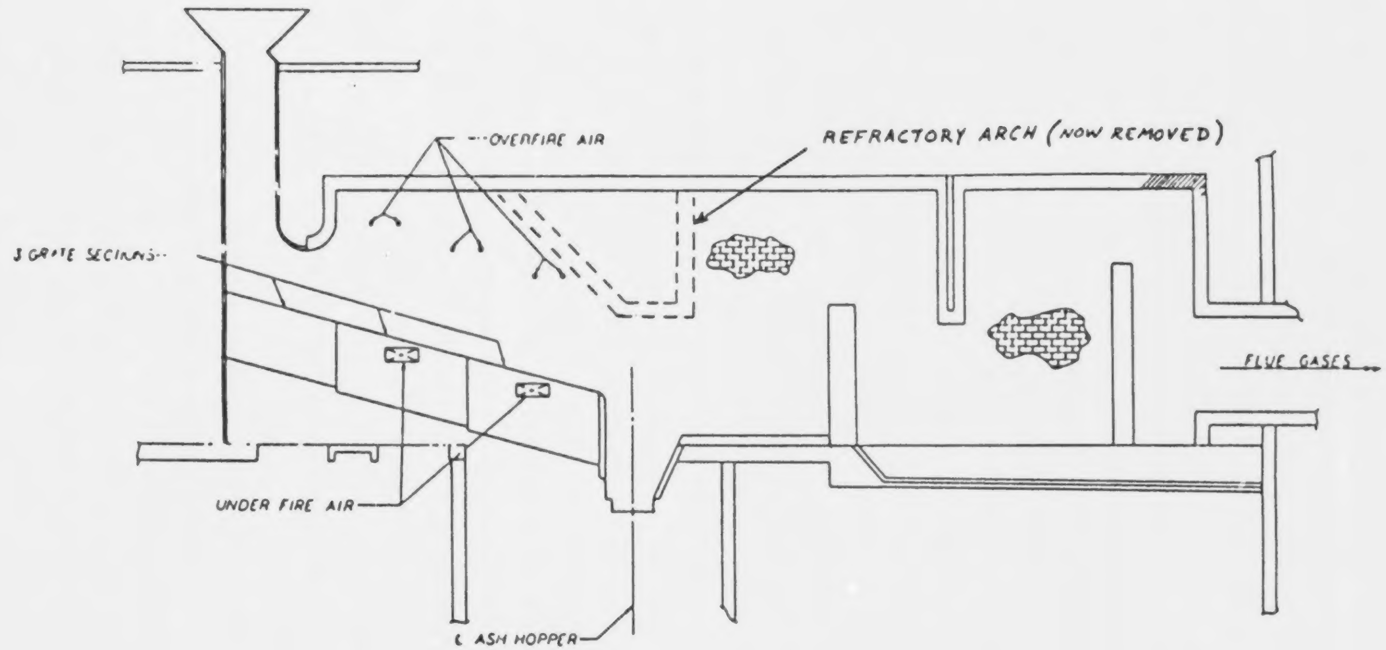
[a] Data are for each combustor. There are two combustors at Sheboygan.



igure 4.2-1. Sheboygan Combustor Profile.

Underfire air is supplied by forced-draft fans (one per combustor) and delivered through ductwork to the burning and finishing grate sections. Siftings hoppers are located beneath the drying grate, but no underfire air is provided to this grate. Separate forced-draft fans (one per combustor) located adjacent to the underfire air fans supply overfire air which is injected at six points on each of the combustor side walls (12 ports per combustor). The overfire air ports are 4 inches square and are located in pairs at elevations approximately 6 to 8 feet above the grates. There are no pressure or flow indicators for either the underfire or overfire air systems. All adjustments in air flow are made manually based on visual observation of the burning fuel bed and flame patterns. Grate speeds are also varied manually by controls on the side of the combustor. The speed of each grate section can be independently set and varied.

As shown in Figure 4.2-1, the original design of the combustor included a refractory arch extending from the top of the combustion chamber, pinching the gas flow from the combustor prior to its exit. The arch was removed and the furnace configuration is now rectangular.

There are no auxiliary fuel burners in either combustor, although natural gas is used to heat the plant offices and adjacent buildings. The combustor is started up by establishing a bed of waste on the first grate section and igniting the waste by hand. Plant operators reported that during start-up it takes approximately 1 to 2 hours to achieve a temperature of 1400°F in the combustion chamber. When this temperature is achieved the overfire air is introduced and the furnace temperature is established at 1700 to 1800°F. The flue gas temperature must be maintained for nearly 20 to 24 hours to bring the refractory temperatures up to the same level. The temperature is measured by a probe in the roof of the combustion chamber located just before the first baffle in the APCD.

4.2.1.2 Emission Control System Design and Operation. Combustion products leaving the active burning region flow through a three-pass wet baffled system which both cools the hot flue gases and reduces particulate matter (PM) emissions. After passing through the wet baffle system, flue gases from both combustion trains are combined in a short run of ducting to the stack.

The original spray nozzles were recently replaced with new stainless steel FOGJET nozzles. The first spray section has 21 full-cone spray nozzles (FOGJET 76 type) and the second spray section has 21 flat-spray nozzles (FOGJET FF type). No changes were made to the nozzle water feed system, which operates at 65 pounds of pressure. During a recent test the PM emissions from the stack varied from 0.226 to 0.326 gr/dscf corrected to 7 percent O_2.

Water and PM collected in the baffle system flow to a concrete lagoon where the ash settles out from the water. Every 3 to 4 months this ash is dredged out and disposed of at a nearby landfill. Approximately 100 tons of lagoon ash are disposed of at each cleaning. The landfill will be shut down at the end of 1988. Overflow water from the lagoon is discharged to the storm sewer which flows to a nearby river. The plant has a discharge permit which requires weekly and quarterly monitoring for BOD, pH, and metals.

4.2.2 Description of Model Plant

4.2.2.1 Combustor Design and Operation. Table 4.2-2 presents model plant baseline data. Based on available information gathered for the other plants in this subcategory, the current design configuration of the Sheboygan MWC is considered representative of the existing population of reciprocating/rocking grate refractory-wall combustors. Although rocking and reciprocating grates vary in design and operation, they are assumed to be equivalent in terms of bed agitation and aeration.

The model plant consists of two rectangular 120-tpd combustors, each with three rocking grate sections. The model operates 24-hr/day, 5-days/week. Fuel feeding is accomplished by gravity and is controlled by manually adjusting the speed of the first (drying) grate section. Underfire air is supplied to the burning and finishing grate sections through individual plenums. Overfire air is supplied through ports in the combustor sidewalls. This arrangement is identical to that described for the Sheboygan plant. All air flows and grate speeds are manually controlled. Separate forced-draft fans supply underfire and overfire air. Continuous monitoring of combustion gases is not conducted.

The model plant burns only MSW and is not equipped with an auxiliary fuel source. At the design feed rate (120 tpd) the theoretical combustion air is approximately 7,150 scfm. Limited emissions testing data available for the

TABLE 4.2-2. MODEL PLANT BASELINE DATA FOR ROCKING/RECIPROCATING GRATE MASS BURN REFRACTORY-WALL COMBUSTOR

Combustor:	
Capacity	- 120 tpd per unit (2 units)
Grate Area	- 202 square feet per unit, 15 degrees slope
Overall Combustor Dimensions	- 28 feet long by 7 feet wide by 15 feet high
Exit Breeching	- Rectangular, 7 feet by 7 feet
Emission Controls:	
Type	- wet baffle chamber
Gas Flow	- 29,400 dscfm, 120,300 acfm at 400°F total
Inlet PM Concentration	- 3.0 gr/dscf at 7% O_2
Emissions[a]:	
CDD/CDF (tetra-octa)	- 4000 ng/dscm
CO	- 50 ppmv
PM	- 0.33 gr/dscf
HCl	- 500 ppmv
SO_2	- 200 ppmv
Solid Waste	- 36 tons per day
Stack Parameters:	
Height	- 150 feet
Diameter	- 9 feet
Operating Data:	
Remaining Plant Life	- 15 years
Annual Operating Hours	- 6,500
Annual Operating Cost	- $3,560,000/year

[a] All values are on a dry, 7 percent O_2 basis.

Sheboygan plant indicate that the excess air level in the stack approaches 300 percent. Therefore, the excess air level assumed for the model was 300 percent. Air inleakage is assumed to be negligible based on the well-sealed appearance of the Sheboygan plant. At an excess air level of 300 percent, the flue gas flow rate is approximately 30,600 scfm (29,400 dscfm), including all flue gas products. At 300 percent excess air the flue gas temperature at the combustor exit is approximately 1400^{0}F.

One design feature of the Sheboygan plant which is considered to be atypical of the population is that Sheboygan does not have an induced-draft fan. It is assumed that the model includes a variable speed induced-draft fan upstream of the stack. The fan automatically adjusts flow rate to maintain a set negative pressure in the combustion chamber.

4.2.2.2 Emission Control System Design and Operation. As shown in Table 4.0-1, seven of the 23 refractory-wall MWC's currently use some type of wet PM control device. The existence of these plants justifies the need for examining retrofit modifications on a plant equipped with such an APCD system. Therefore, while the majority of existing refractory-wall MWC's have ESP's, the model plant for this subcategory is equipped with an APCD system similar to that in place at Sheboygan. The other refractory-wall model plants (see Sections 4.1 and 4.3) are equipped with ESP's.

The model plant for this subcategory uses a wet baffle system for control of PM and temperature. This system is assumed to reduce PM emissions from 3.0 gr/dscf to 0.33 gr/dscf (at baseline). The flue gas temperature is assumed to be reduced from 1400^{0}F to 450^{0}F. No additional PM or acid gas controls are in place at the model plant.

Figure 4.2-2 shows a plot plan of the model plant. Although based on the Sheboygan plant, is is assumed for the purposes of model development that there are moderate access/congestion constraints for the model plant at the APCD end of the system. Although the details of access/congestion constraints are not known for all of the plants in this subcategory, assuming moderate constraints should provide a model plant representative of the majority of plants in the population.

4.2.2.3 Environmental Baseline. Table 4.2-2 presents the environmental baseline for the model plant. There are no available data to directly support a CDD/CDF emissions estimate. However, due to the lack of a distinct point of

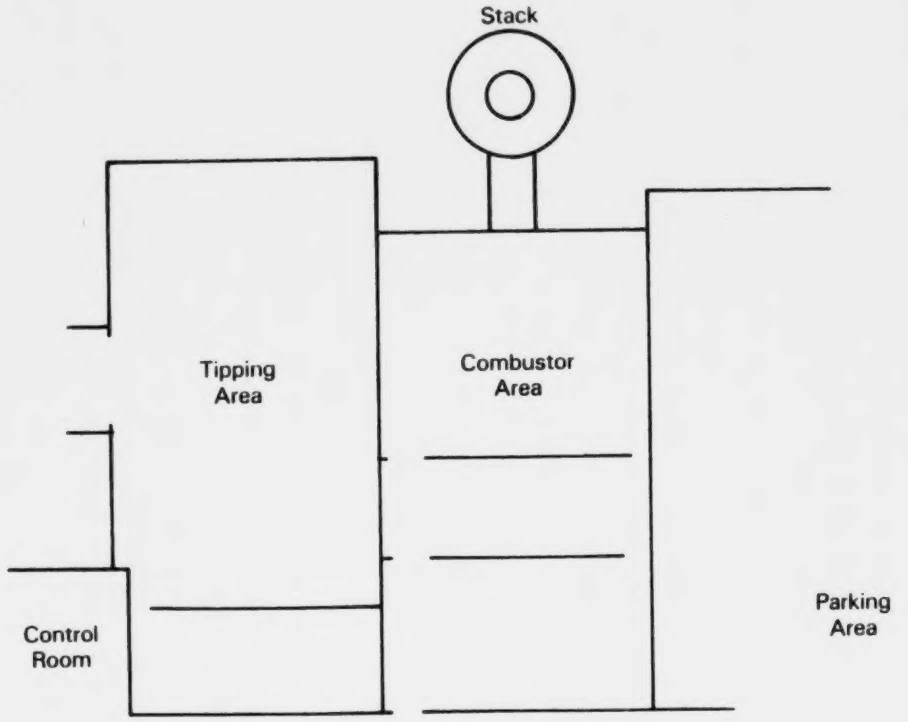


Figure 4.2-2. Plot Plan of Model Plant

high pressure overfire air injection downstream of the finishing grates, mixing of flue gases is assumed to be incomplete. Therefore, relatively high levels of organic emissions are assumed to be present in the flue gases. In addition, the high excess air rates restrict the maximum temperatures that can be achieved in the furnace, so that complete destruction of CDD/CDF and precursors does not occur. As a result, it is assumed the baseline uncontrolled CDD/CDF emission levels are 4,000 ng/dscm.[2]

As a result of less than optimal combustion gas mixing conditions, and low gas temperatures at 300 percent excess air, it is assumed that the oxidation of CO is also incomplete. Uncontrolled CO emissions are estimated to be 500 ppmv at 7 percent O_2.[2] In addition, high excess air levels contribute to increased particulate carryover from the combustion chamber. As a result, baseline PM levels at the combustor exit are estimated to be 3.0 gr/dscf at 7 percent O_2.[2] Emissions of HCl and SO_2 are based on waste feed properties and are not expected to vary appreciably with combustion conditions. Therefore, average uncontrolled values for HCl and SO_2 are estimated to be 500 ppmv and 200 ppmv, respectively, corrected to 7 percent O_2. All baseline emission levels are assumed to be measured at the combustor exit.

The model plant is estimated to achieve a waste volume reduction of 90 percent and a weight reduction of 70 percent. Therefore, the baseline solid waste disposal requirement for each combustor is to be for 36 tpd (dry) ash.

4.2.3 Good Combustion

The following sections describe the modifications required to establish good combustion for the model plant.

4.2.3.1 Description of Modifications.

Fuel Feeding. In the baseline design, the model plant uses gravity feed. As part of the combustion modifications ram feeders will be added to both units. The grates are 8 feet wide, so a single ram is sufficient for each unit. This modification will ensure good waste distribution to the drying grate and more stable combustion conditions. In addition, the ram feeders provide a furnace seal that was previously maintained by waste in the hoppers.

Furnace Reconfiguration. The baseline configuration of the model combustion is not adequate to achieve good combustion. A conceptual redesign of the combustor is illustrated in Figure 4.2-3. The new design includes a

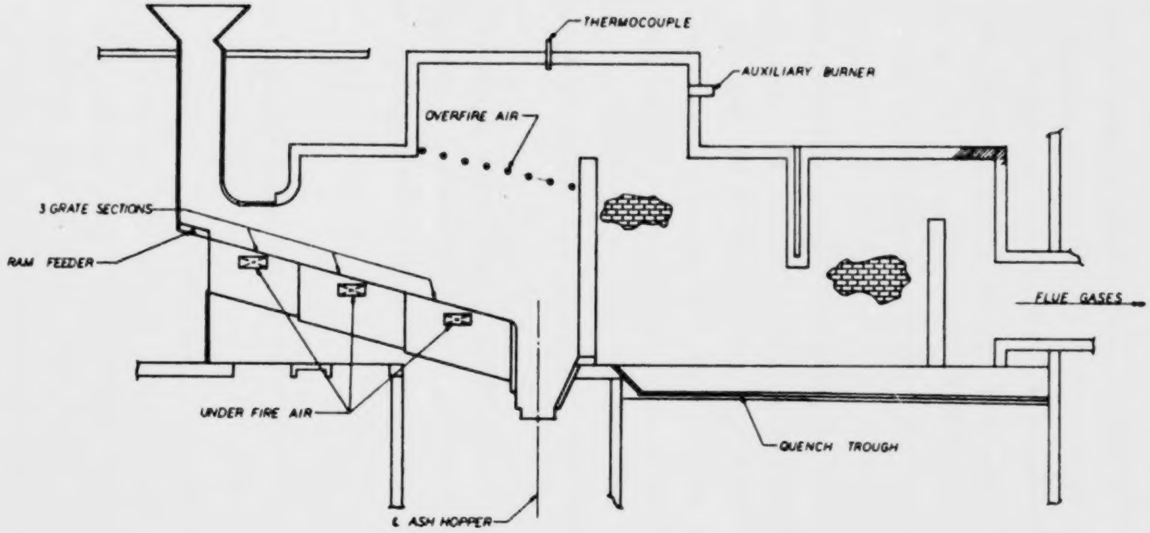


Figure 4.2-3. Model Plant Combustor Profile Showing Combustion Retrofits

refractory-lined structural steel arch which is located on the rear wall of the furnace. In addition, the roof of the furnace has been raised to form an upper combustion chamber where mixing of combustion gases is completed. The retrofit requires partial demolition of the existing walls and roof, and construction of a new furnace shell and refractory brickwork.

Combustion Airflow Modifications. The following modifications are included in the redesign of the model plant's combustion air system.

- Excess air operating levels are reduced from 300 to 150 percent. This allows furnace operating temperatures to be maintained at 1800°F at the fully mixed location. It also reduces the potential for particulate entrainment. At 150 percent excess air, the total gas flow from the combustor is reduced to 19,800 scfm (18,500 dscfm).

- An underfire air plenum with supply ducting, dampers, and pressure monitors is provided for the drying grate section. This underfire air supply has a natural gas burner which can be fired as needed for air preheat when feeding wet refuse. Total undergrate air flows are approximately 125 percent of theoretical air preheat when feeding wet refuse. Total undergrate air flows are approximately 125 percent of theoretical air, or 50 percent of total air.

- New overfire air headers, dampers, ducting, and pressure monitors are installed to provide a source of air for mixing. Two rows of interlaced nozzles are required, as shown in Figure 4.2-3. Flow modeling studies are used to establish nozzle sizes, orientation, spacing, etc. In-furnace CO profiling provides verification of mixing patterns. Approximately 75 percent of theoretical air, or 30 percent of total air, is supplied through these nozzles during normal operating conditions.

- The existing sidewall air nozzles are retained for use as cooling air. New header pressure monitors are required as part of the system upgrade. Approximately 50 percent of theoretical air (20 percent of total air) is supplied by these existing nozzles.

Auxiliary Fuel. The modified model plant has two auxiliary fuel burners, sized to provide 60 percent of unit full load (27 MM Btu/hr) for use during process start-up and during episodes of low temperature and high CO. The first burner is located at the head of the primary combustion chamber above the drying grate, and it is used to ignite the waste and maintain required combustion chamber temperatures. A second burner is located in the upper chamber just downstream of the mixing air supplies. Location of the burner in the upper chamber helps achieve the requirement of 1800°F at the fully mixed height during start-up, shutdown, etc. The upper auxiliary fuel burner also preheats and maintains the temperature of flue gas cleaning equipment prior to initiating waste feeding and during shutdown. This minimizes corrosion problems and improves the system's environmental and operational performance.

Combustion Control. In the baseline configuration, the combustion control scheme is entirely manual. As part of the combustion modifications improved controls are necessary. Because there is no steam production, the primary variables to include in the control scheme are excess oxygen and temperature. The revised controls include an oxygen trim loop which automatically adjusts the amount and distribution of underfire air in response to a signal from an oxygen controller. A temperature controller is included with an alarm at high and low setpoints. Overfire air rates are kept constant. Adjustments in overfire air and grate speed will be made manually, if needed.

Verification. Verification of good combustion consists of insuring that the system is operating according to its design. There are a number of operating parameters that must be monitored and controlled in order to achieve this objective. At a minimum, refractory-wall combustors must continuously monitor:

1. underfire and overfire air flows (pressure settings),
2. combustor draft,
3. O_2 (excess air) and CO in the flue gas, and
4. combustor temperature.

Underfire and overfire air flows are monitored by maintaining specified pressures in supply headers. Combustor draft is maintained by a variable-speed ID fan. Flue gas O_2 and CO are measured at the same location in the system so that the CO reading can be corrected to a standard value, such as 7 percent O_2. Combustor temperature requirements are specified at a location where the mixing process is completed, just downstream of the last point of overfire air injection.

Retrofit Considerations. It is estimated that the combustor downtime required to implement all of the combustion retrofit options is approximately two months per unit.

4.2.3.2 Environmental Performance. The combustion retrofits address the design, operation/control, and verification requirements for good combustion for mass burn refractory-wall combustors represented by this model plant. Through the proper application of the above combustion retrofit options, it is estimated that uncontrolled emissions of CDD/CDF will be reduced to 500 ng/dscm corrected to 7 percent O_2.[2] In addition, emissions of CO are estimated to be reduced to 150 ppmv on a 4-hour averaging time. No change in uncontrolled particulate emissions is expected. Emissions of HCl and SO_2, because they are related to feed properties, are also not expected to vary due to combustion modifications.

4.2.3.3 Costs. Capital costs for combustion retrofits are presented in Table 4.2-3. The total estimated capital cost of the combustion modifications is $3,860,000. Annual costs are presented in Table 4.2-4. The annualized capital cost is $532,000 per year, based on a 10 percent interest rate and fifteen year plant life. Total annualized costs are $847,000.

4.2.4 Good PM Control

4.2.4.1 Description of Modification. The existing baffle quench system is capable of reducing PM loadings at the combustor outlet from 3.0 gr/dscf to 0.33 gr/dscf. This section describes modifications required for adding an ESP to achieve good (0.05 gr/dscf) PM control to the ESP. No temperature control equipment is needed because the flue gas temperature is 450°F.

Achievement of good PM control (0.05 gr/dscf) will require the addition of a new ESP with 16,000 square feet of plate area. This ESP is sized to handle the combined flue gas from both combustors. It is assumed that there is sufficient space near the existing stack to locate the ESP, and that access/congestion constraints are moderate. Approximately 240 feet of flue gas ducting would be required to tie the ESP into the existing ductwork as it leaves the building and return the flue gas to the existing stack. An opacity monitor will be installed at the outlet of the ESP. Figure 4.2-5 shows the location of the ESP and ductwork.

Because of the additional pressure drop caused by the ESP and ducting, a new induced-draft fan will also be required. Approximately 1 month of downtime will be required to tie the new ductwork into the existing ducting to the stack.

TABLE 4.2-3 PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS (Two units of 120 tpd each)

Item		Cost ($1000)
DIRECT COSTS:		
Flow Modeling and Thermal Analysis		125
New Overfire Air Ducting and Dampers		18
Furnace Reconfiguration		1,900
Gas Burner for Air Preheat		4
Two Auxiliary Burners Per Unit		104
Ram Feeders		242
Underfire Air Plenum		28
Underfire and Overfire Airflow Monitors		21
Oxygen and CO Monitors		90
CO Profiling		10
Oxygen Trim Controls on FD Fan		25
	Total	2,670
INDIRECT COSTS AND CONTINGENCY		1,290
TOTAL CAPITAL COSTS		3,860
DOWNTIME COSTS		190
ANNUALIZED CAPITAL COSTS AND DOWNTIME		532

TABLE 4.2-4 PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 120 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Auxiliary Gas Consumption	97
Maintenance Labor	20
Maintenance Materials	20
Total	137
INDIRECT COSTS:	
Overhead	24
Taxes, Insurance, and Administration	154
Capital Recovery and Downtime	532
Total	710
TOTAL ANNUALIZED COSTS	847

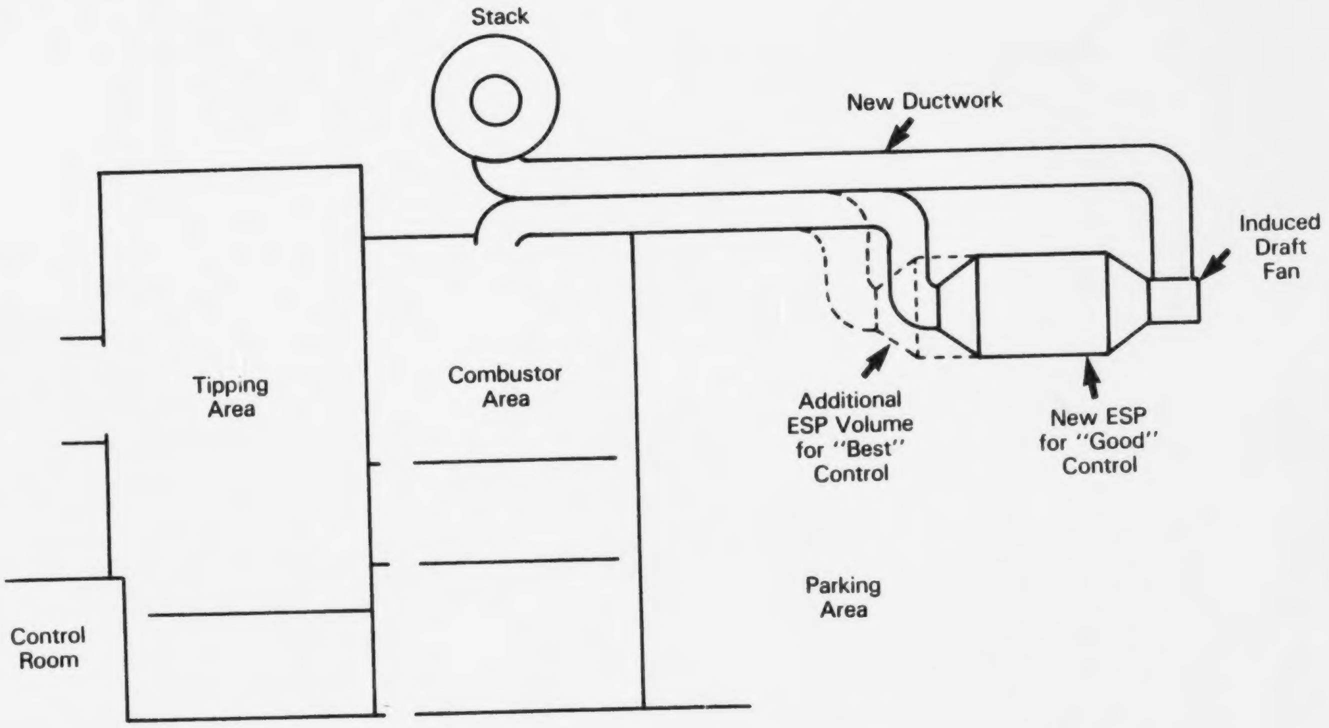


Figure 4.2-4. Plot Plan of Particulate Control Equipment

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4.2.4.2 Environmental Performance. Particulate matter emissions will be reduced from baseline levels of 0.33 gr/dscf to 0.05 gr/dscf. This additional fly ash recovery will add 178 tons/year (dry) to the plant solid waste disposal requirements. CDD/CDF and acid gas emissions are not affected by this modification and are expected to be equal to the concentrations at the combustor exit.

4.2.4.3 Costs. Total capital cost requirements for the new ESP achieving the good particulate control level are presented in Table 4.2-5. Total capital cost is estimated to be $1,800,000. This figure includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion level.

Annual costs are presented in Table 4.2-6 for good particulate control. The costs are dominated by annualized capital recovery and downtime. Indirect annual costs including capital recovery and downtime are estimated at $338,000 per year. Direct operating and maintenance costs are estimated at $55,000 per year. Thus, total annualized cost for good PM control is estimated at $393,000 per year.

4.2.5 Best Particulate Control

4.2.5.1 Description of Modifications. To achieve best PM control (0.01 gr/dscf) will require the addition of an ESP with approximately 29,600 square feet of collection area. No temperature control equipment is needed since the inlet ESP temperature is 450°F. The ESP and new ductwork would be located as shown in Figure 4.2-5. A new induced-draft fan will also be required. Approximately 230 feet of new ducting will be required to divert the flue gases from the building to the ESP and back to the stack. An opacity monitor will be installed at the outlet of the ESP. Approximately one month of downtime is needed to accomplish the ductwork tie-ins.

4.2.5.2 Environmental Performance. Particulate matter emissions will be reduced from 0.33 gr/dscf to 0.01 gr/dscf. The additional recovered fly ash will add 204 tons/yr to the plant total solid waste disposal requirements. CDD/CDF and acid gas emissions are not affected by this modification and are expected to be equal to the concentrations at the combustor exit.

TABLE 4.2-5 PLANT CAPITAL COST FOR NEW PARTICULATE CONTROL
(Two units of 120 tpd each)

Item	Costs ($1000)	
	Good PM Control	Best PM Control
DIRECT COSTS:		
Particulate Control		
Equipment	758	968
Access/Congestion Cost	190	242
New Flue Gas Ducting		
Ducting Cost	122	117
Access/Congestion Cost	30	29
Other Equipment		
Fan	195	195
Stacks	0	0
Demolition/relocation	0	0
Total	1,300	1,606
Indirect Costs and Contingencies	442	529
Monitoring Equipment[a]	60	60
TOTAL CAPITAL COSTS	1,800	2,140
DOWNTIME COSTS	95	95
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	249	294

[a] Turnkey.

TABLE 4.2-6 PLANT ANNUAL COST FOR NEW PARTICULATE CONTROL
(Two units of 120 tpd each)

Item	Costs ($1000) Good PM Control	Costs ($1000) Best PM Control
DIRECT COSTS:		
Operating Labor	10	10
Supervision	1	1
Maintenance Labor	5	5
Maintenance Materials	17	21
Electricity	10	16
Waste Disposal	4	5
Monitors	8	8
Total	55	67
INDIRECT COSTS:		
Overhead	20	22
Taxes, Insurance, and Administration	69	83
Capital Recovery and Downtime	249	294
Total	338	399
TOTAL ANNUALIZED COSTS	393	466

4.2.5.3 Costs. Total capital cost requirements for the best particulate control are presented in Table 4.2-5. Total capital cost is estimated to be $2,140,000. This includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion level.

Annual costs are presented in Table 4.2-6 for best particulate control. Direct operating and maintenance costs are estimated at $67,000 per year. Indirect annual costs are $399,000 per year. Total annualized cost for good PM control is estimated at $466,000 per year.

4.2.6 Good Acid Gas Control

4.2.6.1 Description of Modifications. For good acid gas control, dry sorbent will be injected into new ductwork going to a new fabric filter. The existing water quench system will remain in place. New equipment for the site includes a single sorbent storage silo with baghouse, a pneumatic sorbent conveying system, one sorbent feed bin and pneumatic injection nozzles. Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full-load, this requires a sorbent injection rate of 281 lb/hr for both combustors operating either under baseline or good combustion practices. Reductions in HCl and SO_2 are estimated at 80 and 40 percent, respectively.

The flue gas flow rates at the quench system outlet are 130,500 acfm at $300^{0}F$ for both combustors operating with baseline combustion, and 91,700 acfm at $300^{0}F$ for both combustors operating with good combustion. This temperature reduction is achieved by an additional water quench of 19 and 12 gpm in the existing wet baffle system for baseline and good combustion, respectively.

The new fabric filter will require 240 feet of new ductwork and a new induced-draft fan to overcome the pressure drop. Approximately 43,500 and 30,600 square feet of fabric filter cloth will be required (based on a gross air-to-cloth ratio of 3:1) for baseline and good combustion, respectively. The project also includes monitoring equipment for HCl, SO_2, O_2, and opacity. These monitors will be located in the ducting prior to sorbent injection and also at the outlet of the fabric filter. An opacity monitor will also be installed at the outlet of the fabric filter.

Figure 4.2-5 shows the location of the equipment. Moderate access/congestion levels were assumed for the ductwork and fabric filter. Moderate access/congestion levels were also assumed for the lime receiving, storage and conveying equipment. Advanced planning will be required to limit combustor downtime to approximately one month.

4.2.6.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 75 percent from outlet combustor levels. Acid gas emission reductions are estimated at 80 percent for HCl and 40 percent for SO_2, respectively. PM emissions are 0.01 gr/dscf. An additional 1,380 tons/year of sorbent and fly ash will be added to the baseline solid waste disposal requirements, or either combustion practices.

4.2.6.3 Costs. Total capital cost requirements for dry sorbent injection are presented in Table 4.2-7 for baseline and good combustion. Most of the cost is associated with particulate control equipment. Total capital cost is estimated at $4,320,000 for baseline combustion and $3,510,000 for good combustion. Both estimates assume moderate APCD access/congestion level.

Annual O&M and indirect costs are presented in Table 4.2-8 for both combustion practices. Major direct operating costs are associated with maintenance materials, electricity, lime, and monitor maintenance. The largest annualized cost is the capital recovery and downtime. The total annualized cost for the modification is $1,400,000 per year for baseline combustion and $1,170,000 for good combustion.

4.2.7 Best Acid Gas Control

4.2.7.1 Description of Modifications. For best acid gas control a new spray dryer/fabric filter system will be installed to treat the total flue gas from both combustors. Lime slurry will be fed to a single spray dryer at a 2.5:1 molar calcium-to-acid gas ratio. Lime will be slurried in sufficient water to cool the flue gas to from 450°F to 300°F at a rate of 19 and 12 gpm for baseline and good combustion, respectively. A fabric filter with 43,500 and 30,600 square feet of cloth (gross air-to-cloth ratio of 3:1) will be installed following the spray dryer for baseline and good combustion practices, respectively. The project also includes monitoring equipment for HCl, SO_2, O_2, and opacity.

TABLE 4.2-7 PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH FABRIC FILTER (Two units of 120 tpd each)

Item	Costs ($1000) Baseline Combustion Practices	 Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control		
Equipment	198	198
Access/Congestion Cost[a]	20	20
Particulate Control		
Equipment	1,200	932
Access/Congestion Cost	294	233
New Flue Gas Ducting		
Ducting Cost	144	121
Access/Congestion Cost	36	30
Other Equipment		
Fan	253	180
Stacks	0	0
Demolition/relocation	0	0
Total	2,150	1,710
Indirect Costs and Contingencies	1,890	1,510
Monitoring Equipment[a]	286	286
TOTAL CAPITAL COST	4,320	3,510
DOWNTIME COST	94	94
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	580	474

[a] Turnkey.

TABLE 4.2-8 PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH FABRIC FILTER (Two units of 120 tpd each)

Item	Costs ($1000)	
	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Operating Labor	40	40
Supervision	6	6
Maintenance Labor	16	16
Maintenance Materials	150[a]	116[b]
Electricity	105	76
Compressed Air	17	12
Water[c]	4	0
Lime	73	73
Waste Disposal	35	35
Monitors	107	107
Total	553	480
INDIRECT COSTS:		
Overhead	101	88
Taxes, Insurance, and Administration	161	129
Capital Recovery and Downtime	580	474
Total	842	691
TOTAL ANNUALIZED COST	1,400	1,170

[a] Includes bag replacement costs of $42,000.

[b] Includes bag replacement costs of $30,000.

[c] Incremental increase in water costs from baseline.

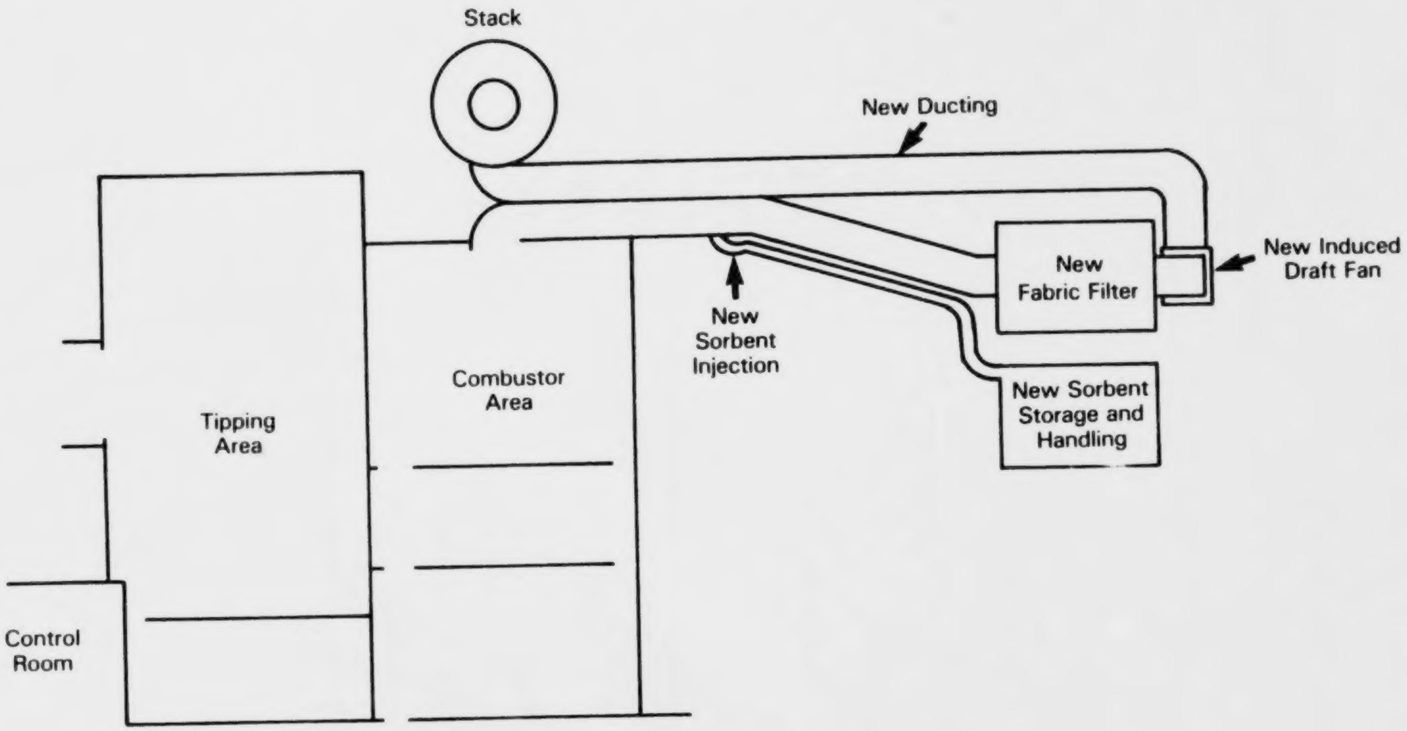

Figure 4.2-5. Plot Plan of Dry Sorbent Injection/Fabric Filter Equipment Arrangement.

Monitors for HCl, SO_2, and O_2 will be located in the ducting before the spray dryer and at the outlet of the fabric filter. An opacity monitor will also be installed at the outlet of the fabric filter.

This arrangement will require about 270 total feet of new duct, but will allow the existing stack to be reused. The proposed equipment layout is illustrated in Figure 4.2-6. This sketch also shows the location of the lime receiving, storage, and slurry area and the location of the waste storage silo. Access and congestion levels are assumed to be moderate for the flue gas ducting, spray dryer/fabric filter and the sorbent preparation and waste silo. Advanced planning will be required to limit combustor downtime to approximately one month.

4.2.7.2 Environmental Performance. Total CDD/CDF emission reductions of 99 percent from the combustor outlet levels or to 5 ng/dscm, whichever is greater, are expected. Emissions of particulate matter will be reduced from 0.33 gr/dscf to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl. Solid waste will be increased by 1,240 tons/yr relative to baseline.

4.2.7.3 Costs. Capital cost requirements for installing a spray dryer/fabric filter system are presented in Table 4.2-9 for baseline and good combustion. Total capital cost is estimated at $9,600,000 and $8,020,000 for baseline and good combustion conditions, respectively. This figure includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion.

Annual O&M and indirect costs are presented in Table 4.2-10. Total annualized cost of good acid gas control are $2,350,000 and $1,990,000 per year for baseline and good combustion, respectively.

4.2.8 Summary of Control Options

4.2.8. Description of Control Options. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 4.2-11 summarizes the combustion, particulate control, and acid gas control technologies described in Section 4.2.3 through 4.2.7 that were combined for each of the control options described in Section 3.0.

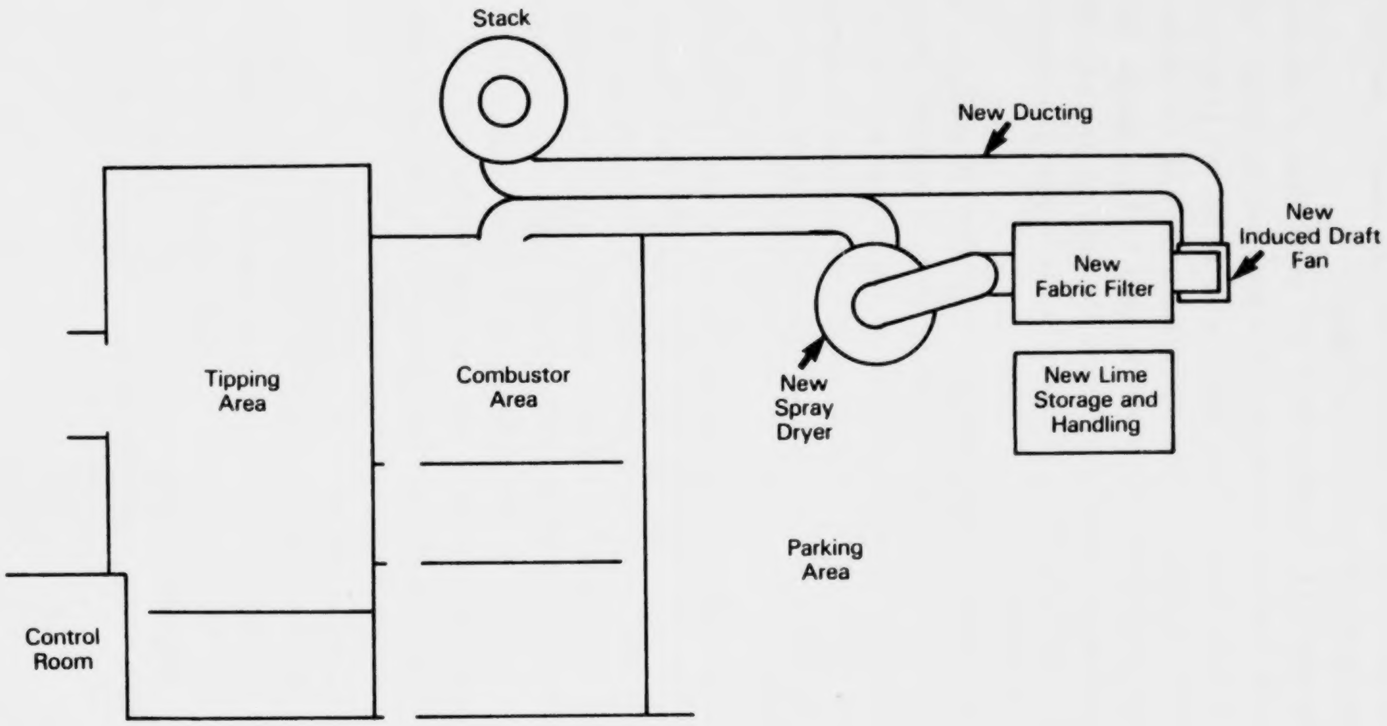

Figure 4.2-6. Plot Plan of Spray Dryer/Fabric Filter Equipment Arrangement.

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TABLE 4.2-9 PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 120 tpd each)

Item	Costs ($1000) Baseline Combustion Practices	Costs ($1000) Good Combustion Practices
DIRECT COSTS:		
Acid Gas and Particulate Control Equipment	4,290	3,580
Access/Congestion Cost[a]	1,070	899
New Flue Gas Ducting		
Ducting Cost	162	136
Access/Congestion Cost	41	34
Other Equipment		
Fan	271	194
Stacks	0	0
Demolition/relocation	0	0
	5,840	4,840
Indirect Costs and Contingencies	3,480	2,880
Monitoring Equipment	286	286
TOTAL CAPITAL COST	9,600	8,020
DOWNTIME COSTS	94	94
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	1,270	1,070

[a] Turnkey.

TABLE 4.2-10 PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 120 tpd each)

Item	Costs ($1000)	
	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Operating Labor	39	39
Supervision	6	6
Maintenance Labor	21	21
Maintenance Materials	159[a]	127[b]
Electricity	132	94
Compressed Air	20	14
Water	4	2
Lime	60	60
Waste Disposal	44	44
Monitors	107	107
Total	592	514
INDIRECT COSTS:		
Overhead	110	98
Taxes, Insurance, and Administration	373	309
Capital Recovery and Downtime	1,270	1,070
Total	1,750	1,480
TOTAL ANNUALIZED COST	2,350	1,990

[a] Includes bag replacement costs of $42,000.

[b] Includes bag replacement costs of $30,000.

TABLE 4.2-11 SUMMARY OF CONTROL OPTIONS FOR ROCKING/RECIPROCATING GRATE MASS BURN REFRACTORY-WALL COMBUSTOR

		Particulate Matter Control		Acid Gas Control	
Control Option Description	Combustion Modifications	New ESP	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion Control	X				
2. Good PM Control and Combustion Control	X	X			
3. Best PM Control and Combustion Control	X	X			
4. Good Acid Gas Control and Best PM Control			X	X	
5. Good Acid Gas Control and Best PM/Combustion Control	X		X	X	
6. Best Acid Gas Control and Best PM Control			X		X
7. Best Acid Gas Control and Best PM/Combustion Control	X		X		X

4.2.8.2 Environmental Performance. The performance of each control option is summarized in Table 4.2-12. For each pollutant the table presents both the pollutant concentrations and annual emissions. The greatest on acid gases, particulate matter, and CDD/CDF all are achieved with a spray dryer/ fabric filter system. The next most effective control for all these pollutants is the dry sorbent injection technology. Dry sorbent injection technology increases the baseline solid waste disposal by about 6.5 percent, and the spray dryer/fabric filter system increases the baseline solid waste disposal by about 5.8 percent. CO reduction of 70 percent from baseline is achieved for those options having good combustion.

4.2.8.3 Costs. The total annualized cost of each option is presented in Table 4.2-13. The most expensive control option is the spray dryer/fabric filter installation with combustion modification (Option 7). The total capital costs for this option is 11,900,000 and the total annualized cost is $2,820,000. This annualized cost is roughly 3 times higher than the annualized costs for Option 1. Overall, both capital and annualized costs are higher for higher levels of control.

4.2.8.4 Energy Impacts. Table 4.2-14 presents a summary of the energy impacts associated with the control options. The energy use figures are incremental use from baseline. The spray dryer with fabric filter control options consume the most electricity of the two fabric filter options, Option 6 consumes more electricity at a rate of 2,870 MWh per year. Auxiliary fuel is fired for those options requiring combustion modification all at a rate of 22 billion Btu per year.

TABLE 4.2-13 COST SUMMARY FOR MASS BURN RECIPROCATING GRATE REFRACTORY-WALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 120 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	3,860	5,660	6,000	4,320	7,370	9,600	11,900
Downtime Cost	190	190	190	95	190	94	190
Annualized Capital Cost and Downtime	532	769	813	580	994	1,270	1,590
Direct O & M Cost	137	192	204	553	617	592	651
Total Annual cost	847	1,230	1,300	1,400	2,000	2,350	2,820
Cost Effectiveness ($/ton MSW)	13.70	19.80	21.00	22.60	32.30	37.90	45.50
Facility Downtime (Months)	2	2	2	1	2	1	2
Total Compliance Time (Months)	9	19	19	19	19	25	25

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[a] All costs (except cost effectiveness) given in $1000. All costs are December 1987 dollars.

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TABLE 4.2-14 ENERGY IMPACTS FOR ROCKING/RECIPROCATING MASS BURN REFRACTORY-WALL COMBUSTOR CONTROL OPTIONS

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	2.2E10
2	217	2.2E10
3	349	2.2E10
4	2,280	0
5	1,650	2.2E10
6	2,870	0
7	2,030	2.2E10

4.3 GRATE/ROTARY KILN REFRACTORY-WALL COMBUSTOR

This section presents the case study results for a mass burn refractory-wall MWC using a split flow configuration with a rotary kiln. As shown in Table 4.0-1, there are 5 known plants of this type. Section 4.3.1 presents a description of the Montgomery County (Dayton) Ohio, plants, which were visited to gather information for model development. Section 4.3.2 presents a description of the model plant. Sections 4.3.3 through 4.3.6 describe the retrofit modifications, estimated performance, and costs associated with various retrofit controls. Section 4.3.7 presents a summary of the control options, which are described in more detail in Section 3.0 of this report.

4.3.1 Description of Montgomery County, Ohio Plants[4]

Montgomery County, Ohio operates two MWC plants, referred to as the North and South plants. Both plants began operating in 1970 using nearly identical designs, and both plants are currently undergoing expansions which are expected to be complete in 1988. The original design at each plant consisted of two 300 tpd Volund refractory-lined combustors (#1 and #2) with reciprocating grate sections followed by a rotary kiln. The units are illustrated in Figure 4.3-1. The original air pollution controls consisted of low energy wet scrubbers. Electrostatic precipitators (ESP's) were added to all of the existing combustors in the early 1980's. The original wet scrubbers are now used as cooling and mixing chambers.

The current facility expansions will add a third 300 tpd combustor (#3) at each plant site. The #3 combustor at the North plant is equipped with a Combustion Engineering waste heat boiler with a design capacity of 82,000 lb/hr of steam at 750 psig and 750^{0}F, and a 6 MW extraction turbine. Space is being provided at the South plant for a similar boiler design to be added later to its #3 combustor. Boiler addition at the South plant is contingent on the successful operation of the boiler at the North plant. The description of the plants which follows will apply to the existing combustors (#1 and #2) at either of the plants. Where design and operations differ between the two plants these differences will be identified.

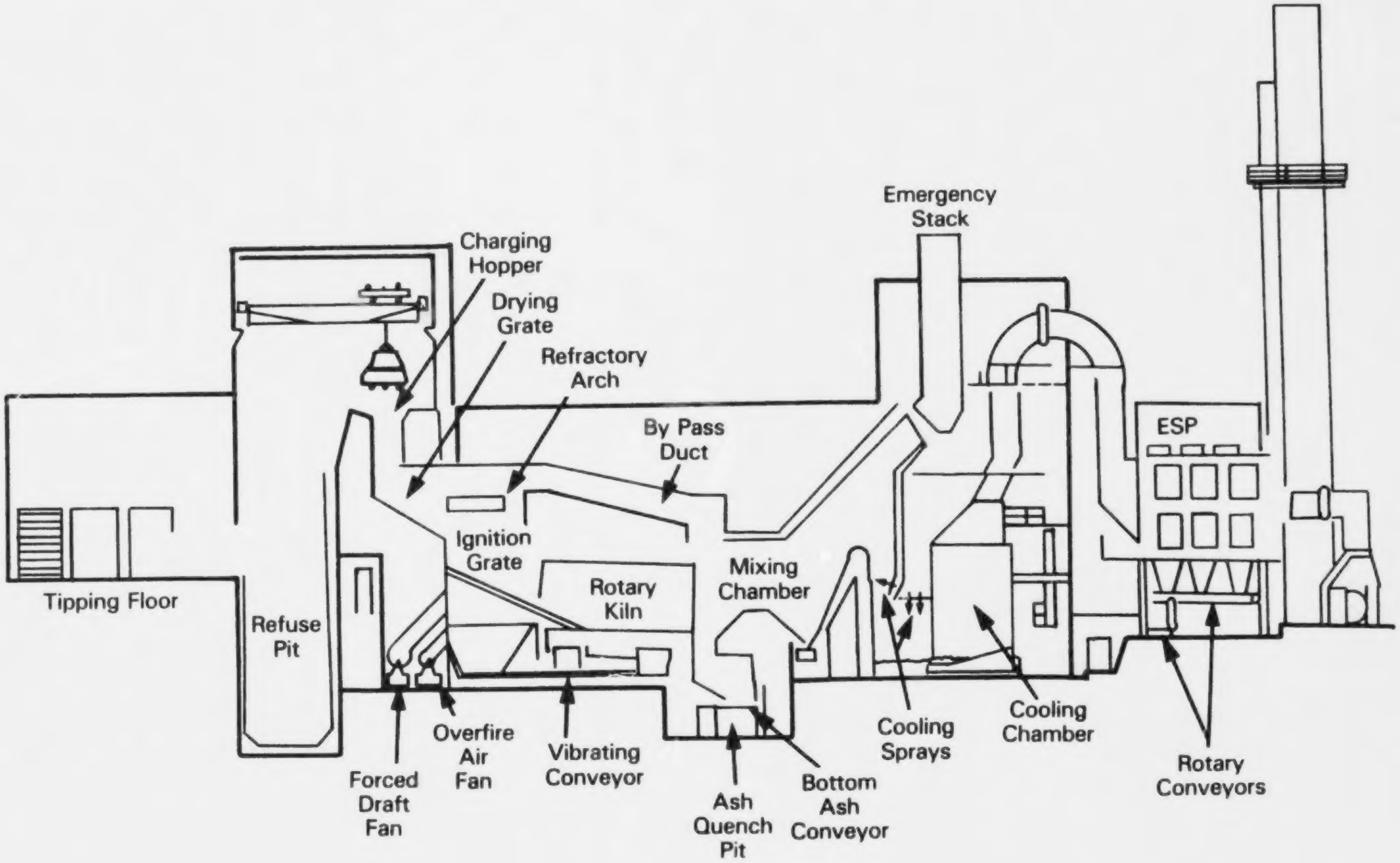

Figure 4.3-1. Profile of Original Combustor (#1 and #2) at Montgomery County, OH.

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4.3.1.1 Combustor Design and Operation. The two existing combustors operate 24 hours/day, 7 days/week, with as few shutdowns as possible. Waste is dumped by trucks into a large holding pit where it is mixed by an overhead crane and charged to individual combustor feed hoppers. Both plants have experienced pit fires in the past. This problem has been addressed with installation of emergency water hoses on the ceiling of the building above the holding pit. Waste is fed to each combustor by gravity. The feed rate is controlled by the speed of the first grate section. A profile sketch of the existing combustors is shown in Figure 4.3-1, and operating and design data are presented in Table 4.3-1.

Waste tumbles from the feed chute onto the first of two short drying grate sections, where moisture is released prior to ignition. A grate step of about two feet separates the two sections. No underfire air is supplied to the drying grates. Hoppers are located beneath the grates to catch waste which falls through. The siftings and riddlings are conveyed to the ash disposal system. A transverse refractory arch is located above the drying grate sections in 3 of the 4 existing combustors at the 2 plants to provide radiative heat to the drying grates. Existence of these arches does not appear to be an essential design feature, however. The #1 combustor at the North plant no longer has the transverse arch, and the design being used in the #3 combustors will include a vertical arch rather than the transverse design (see Figure 4.3-2).

From the second drying grate section waste tumbles approximately 5 feet down onto the ignition grate, where active burning takes place. Individual forced-draft fans supply underfire air to a single windbox beneath the ignition grate in each of the combustors. This flow is adjusted manually by a damper located in the supply header. Underfire air is drawn from the pit area. The windbox is not well sealed, as the air is not highly pressurized. When these fans are inoperable the system operates with only the ID fan pulling air through the windbox.

Flue gas temperatures are measured by a thermocouple located in the roof of the ignition chamber and are displayed in the control room. Normal operating temperatures in the ignition chamber were reported to be 1,700 to 1,800^{0}F. Two sidewall overfire air ports (4 inch square) are located on

TABLE 4.3-1. MONTGOMERY COUNTY, OHIO DESIGN DATA

General:	
Number of combustors at each plant	- 2 (3 with expansion)
Type	- Reciprocating grate followed by rotary kiln.
Combustor capacity	- 300 tpd each
Plant Capacity	- 600 tpd (900 tpd with expansion)
Kiln Parameters:	
Length	- 30 feet
Diameter	- 10 feet
Maximum Kiln Speed	- 10 rph
Gas Conditioning:	
Conditioning Chamber	- 27 feet in length 28 feet in height
Maximum Cooling Water Flow	- 180 gpm
Particulate Emission Controls:	
Type	- Electrostatic Precipitator
Manufacturer	- United - McGill
Number of ESP's	- 2 (one per combustor)
Number of Fields	- 3 per ESP
Operating Temperatures	- 450 to 600°F
Design Outlet Grain Loading	- 0.03 gr/dscf at 12% CO_2
Particulate Emission Limit	- 0.03 gr/dscf at 12% CO_2
Gas Flow	- 100,000 acfm
Total Plate Area	- 32,580 square feet
SCA @ 100,000 acfm	- 326
Residence Time	- 8 seconds
Dimensions:	
Length	- 30 feet
Width	- 20 feet
Height	- 30 feet
Particulate Matter Emissions (March 1985)	- 0.036 gr/dscf at 12% CO_2
Acid Gas Emission Control:	
Furnace Sorbent Injection	

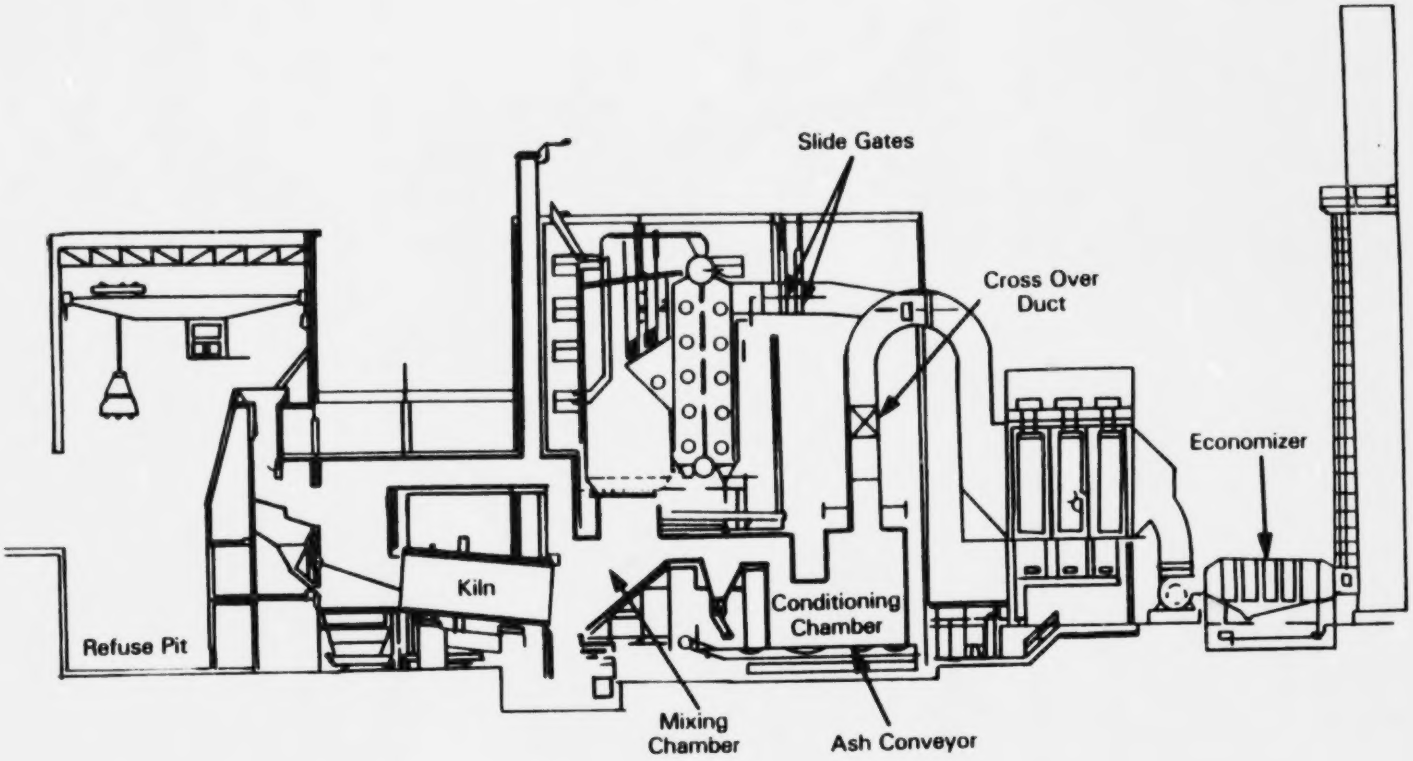

Figure 4.3-2. Profile of New Combustor (#3) at Montgomery County (North), OH.

each side of the combustor approximately 5 feet above the level of the grate. These air ports are the last point of controlled air injection to the system. However, there are numerous points of air inleakage from ports, doors, and seals downstream. A single overfire air fan with an operating pressure of 27 inches of water head capacity provides overfire air to both existing combustors (#1 and #2). Thus, loss of this fan eliminates the overfire air supply to both units.

Burning waste is discharged from the ignition grate and falls approximately 4 feet into a refractory-lined rotary kiln. The kiln is approximately 10 feet in diameter and 30 feet in length. The kiln rotates at a maximum speed of 10 rph. The kiln is a co-flow design; flue gases flow in the same direction as the waste. Burnout of solids is achieved through long retention times in the kiln. Bottom ash is discharged from the kiln and falls into a water quench pit where it is removed by a drag chain conveyor.

The flow of combustion gases from the ignition chamber is split, with portions flowing through the rotary kiln or through a refractory-lined overhead bypass duct. The split flows converge in a mixing chamber downstream of the rotary kiln (see Figure 4.3-1). A thermocouple is located on the roof of the mixing chamber. Typical operating temperatures in this region vary from 1,700 to 1,900^{0}F. The gases then flow to a cooling chamber where water sprays lower their temperatures to approximately 600^{0}F. Typical water spray rates were reported to vary from 80 to 110 gpm. The maximum cooling water flow rate is about 180 gpm. The flow of water is adjusted automatically to maintain a temperature set point at the ESP inlet. An emergency dump stack is located at the top of the mixing chamber for use when the ESP's or water sprays are inoperable.

Grate System. The existing combustors were originally equipped with Volund cast iron grate systems. As the cast iron grates have failed, they have been replaced by a custom design which was fabricated specifically for the two plants. The new stainless steel grates are arranged in 13 rows, called stringers, across the width of the grate section (side wall to side wall). Underfire air passes up through slots located between the grates and at the front of the grate nose. The South plant has drilled holes through the top of the grate bars, while the North plant uses solid sections. No design or operational advantages have been realized from either grate system to date.

Combustion Controls. The combustors are operated on a manual control scheme. Air flows and grate and kiln speeds are adjusted manually based on visual observations of the burning process and on the temperature readings at the various stages through the system. The combustor draft requires a manual setting on the ID fan with automatic control to maintain -0.25 inches of water pressure in the ignition chamber and -0.7 inches of water in the mixing chamber. As mentioned above, temperatures in the ESP are maintained by the adjustment of the water sprays in the cooling chamber. With the addition of the third combustor the controls will all be consolidated at one new location in the building. They will, however, remain largely manual.

Ash Disposal. Siftings, riddlings, bottom ash, and fly ash are combined in the wet ash quench and removed from the building by a drag chain conveyor. All of the ash from both plants is buried in a single landfill site adjacent to the North plant. The ash at the South plant is stored temporarily behind the plant until it can be trucked to the North site landfill. Private scavengers are permitted to remove and reclaim scrap metals from the landfill site prior to burial, and a base price per ton of metal recovered is paid to the County. The landfill site is lined with clay and was reported to be equipped with groundwater monitoring wells. No substances other than ash are disposed of in the landfill at the North plant.

Start-Up/Shutdown. None of the existing combustors is equipped with a source of auxiliary fuel. The plants reported that they almost never have both existing combustors off line at any given time. A crossover duct is located in the hairpin duct section downstream of the conditioning chamber, connecting both combustors. When one unit is started up, the crossover duct is opened and hot gases from the other combustor are used to preheat the cold ESP. However, the combustors are started up by igniting the waste and gradually developing stable burning patterns. From a cold start the refractory takes up to 24 hours to reach steady state operating temperatures.

Auxiliary gas burners are reportedly being added in the mixing chamber of the new combustor (#3). Shutdown is achieved simply by burning out the waste in the system and letting the combustor cool.

Facility Expansion. As mentioned previously, the #3 combustor at the North plant will include a waste heat boiler and turbine generator, and the South plant is providing space to include a similar design. The arrangement at the North plant is depicted in Figure 4.3-2. The basic configuration does not change appreciably from that of the existing combustors. Specific changes include:

- A vertical refractory arch hangs from the combustor roof,
- the riddlings conveying system uses a wet chain conveyor rather than a vibrating conveyor,
- the riddlings hopper is water sealed,
- the windbox under the ignition grate will be sealed, and
- air is injected through fan ports on the back wall of the ignition chamber, where waste builds up.

Sufficient fan capacity is available in the two underfire air fans and the single overfire air fan that service the existing combustors so that ducting from these units can supply air to the #3 combustor.

An interesting design feature of this system is the operational flexibility provided to the plant through a boiler bypass. This bypass provides a flue gas flow path similar to that used in the existing combustors. Plant personnel estimate that 75 percent of the flue gas will normally pass through the boiler and 25 percent through the bypass. However, all of the flue gas can pass through the bypass, allowing incineration to continue in the event that the boiler must be removed from service for maintenance or other reasons. In the new unit, design attention was focused on unit reliability rather than on maximized steam production.

The boiler will be operated at 500 psig and 650^{0}F, considerably below its design rating (750 psig at 750^{0}F). Boiler load will also be slightly less than rated capacity (82,000 lb/hr of steam). Additional safety factors were taken into account in the boiler design by providing an additional 1/2 inch of steel on all areas of the steam drum that come into direct contact with flue gases. Waterwall and superheater tube wastage experienced at other resource recovery plants due to flame impingement and particulate carryover are not expected to occur in the current design because of the remote locations of heat transfer surface relative to the active burning regions.

Electricity will be generated by a 13-stage Murray steam turbine and sold to the local grid. The price was under negotiation during the time of the site visit. The plant does not currently have a steam customer, but a blind connection has been provided in the boiler design. A fin tube economizer is located downstream of the ID fan to preheat boiler feedwater. Feedwater treatment equipment is located on site, and without sale of steam, make-up water is minimal.

4.3.1.2 Emission Control System Design and Operation. Each combustor is equipped with a dedicated 3-field ESP manufactured by United-McGill. Table 4.3-1 presents design and operating data for the ESP's, and Figure 4.3-3 shows a plot plan of the South plant. Flue gases flow upward from the cooling chamber through a hairpin duct and enter the ESP. A thermocouple located at the top of the hairpin duct measures the temperature at this point and controls the rate of water injection upstream in the cooling chamber. Setpoint temperatures reportedly vary from 500 to 590°F.

The plates are made of COR-TEN steel so that a protective coating of rust forms early after installation, preventing further corrosion.[5] The plant reported that the ESP's have been operated below 500°F, but long-term operation at these temperatures has resulted in deposits of an unknown substance on the plates that must be periodically "baked off" at temperatures in excess of 600°F. Measured particulate data provided by the State regulatory office indicated that the ESP's have achieved an average grain loading of 0.036 gr/dscf corrected to 12 percent CO_2 (March 1985 compliance test results).

Each plant has one stack for the two existing combustors. A new stack is being constructed at each plant for dedicated use with the new combustors. An opacity monitor is located in each stack. Opacity was observed to be about 5 percent during the 2-day visit.

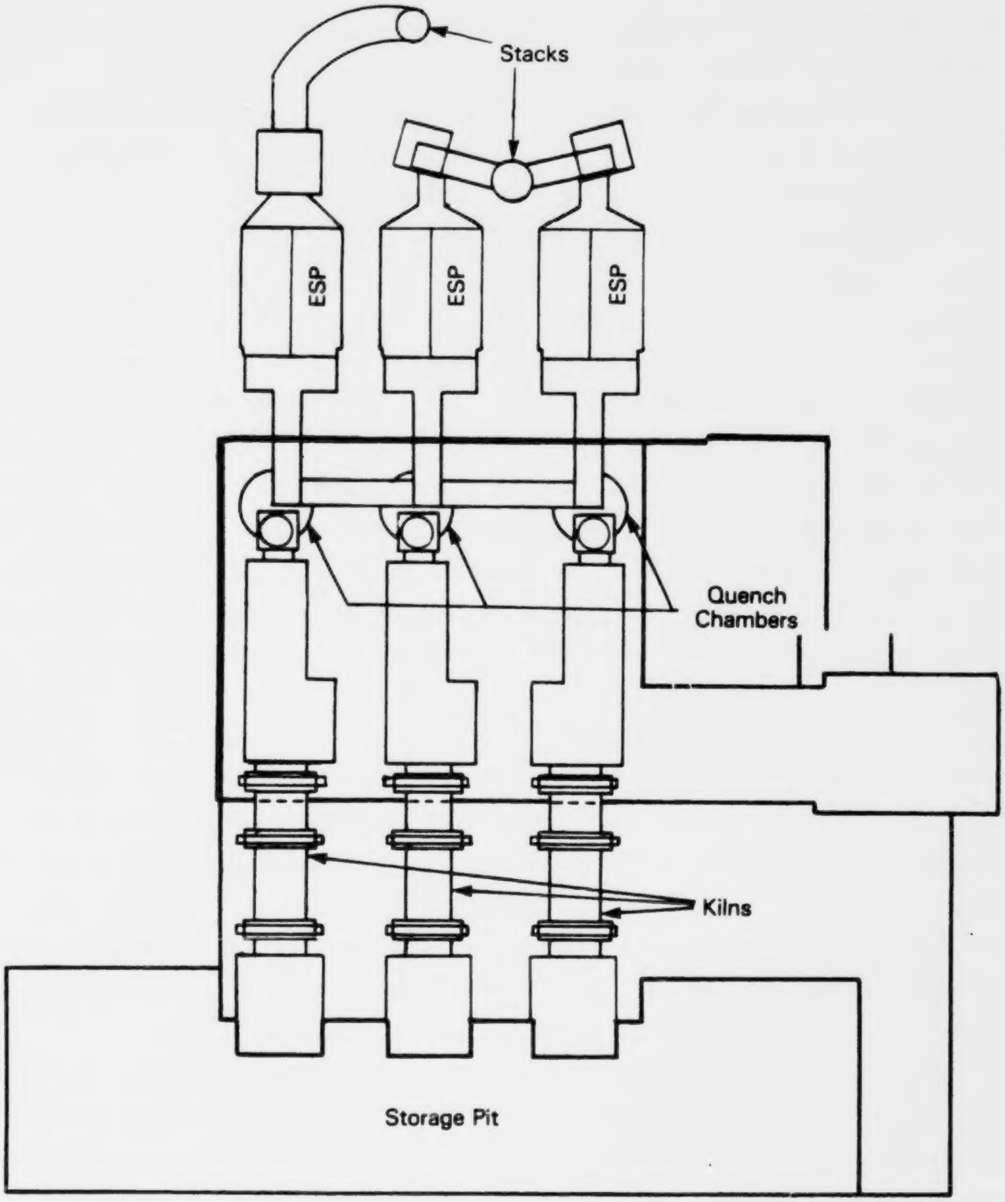

Figure 4.3-3. Plot Plan of Montgomery County (South), OH.

With the construction of the new combustors (#3), a number of air permitting issues arose concerning SO_2 emission levels and BACT determinations. The plants installed combustor dry sorbent injection systems on the existing combustors (#1 and #2) to reduce SO_2 emissions and allow erection of the #3 combustors.

Crushed limestone is pneumatically conveyed from a storage silo one cubic foot at a time to a three cubic foot surge bin. A meterable auger feeding system feeds the limestone to a venturi device, which injects limestone into the overfire air ducts. After experimenting with a number of sorbents, crushed limestone was selected due to lower costs than lime. The limestone is injected into the flue gas at a rate of 135 to 160 lb/hr per combustor. Limited emissions testing indicates that somewhat less than 30 percent SO_2 reduction is achieved. These results were documented by continuous SO_2 monitors at the stack while the sorbent injection system was operating and then turned off. The State emission limit for SO_2 is 2.5 lb/ton of waste charged. The marginal control efficiency of these systems has permitted the plants to comply with this regulation and avoid PSD applicability for SO_2. No impact on fly ash amount or ESP performance has been noted by the operators since operation of the injection system began.

4.3.2 Description of Model Plant

4.3.2.1 Combustor Design and Operation. The configuration of the combustion system is similar in configuration to that of the existing units at the Montgomery County, OH plants. This is typical of the four other facilities in this subpopulation. The model plant is comprised of three combustors, each with a design capacity of 300 tpd. It is assumed that the plant operates at 100 percent capacity, 24-hours/day, 7-days/week. Baseline data for the model plant is shown in Table 4.3-2.

The plant uses early Volund technology, which consists of two drying grates, a burning (ignition) grate, and a refractory-lined rotary kiln. Waste feeding is accomplished by gravity and controlled by manual adjustment of the first drying grate section. Each of the combustors has separate underfire and overfire air fans. Underfire air is supplied beneath the

TABLE 4.3-2. MODEL PLANT BASELINE DATA FOR GRATE/ROTARY KILN REFRACTORY-WALL COMBUSTOR

Combustors:	
Capacity	- 3 units at 300 tons per day each
Rotary Kiln	- 30 feet in length
	- 10 feet diameter
	- 10 rpm maximum speed
Design Percent Excess Air	- 250 percent
Total Excess Air (including inleakage)	- 275 percent
Gas Conditioning:	
Inlet PM Loading	- 3.0 gr/dscf at 7 percent O_2
Conditioning Chamber	- 27 feet in length
	- 28 feet in width
Emission Controls:	
Type	- 3-field ESP
Number	- 3, one per combustor
Gas Flow	- 210,000 acfm at 550°F
Collecting Area	- 53,000 square feet
SCA at 210,000 acfm and 550°F	- 250 square feet per 1000 acfm
Inlet PM Loading	- 1.0 gr/dscf at 7 percent O_2
Emissions[a]:	
CDD/CDF (tetra-octa) (stack)	- 6,000 ng/dscm
CO	- 500 ppmv
PM (stack)	- 0.03 gr/dscf at 7 percent O_2
HCl	- 500 ppmv
SO_2	- 200 ppmv
Solid Waste	- 270 tpd
Stack Parameters:	
Height	- 120 feet
Diameter	- 8 feet
Operating Data:	
Remaining Plant Life	- 15 years
Annual Operating Hours	- 8,000
Annual Operating Cost	- $9,910,000/year

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[a] All values are dry, corrected to 7 percent O_2. Standard and normal conditions are both 1 atmosphere and 70°F. All emissions except PM and CDD/CDF are measured at combustor exit.

ignition grate just upstream of the rotary kiln. There is no underfire air supplied to the drying grates. Overfire air is supplied on each of the side walls of the ignition chamber through two square ports. Control of both air supplies is totally manual (based on individual damper settings). Grate speeds and rotary kiln rotational speeds are manually adjusted.

Theoretical air requirements are approximately 17,800 scfm at full capacity. Based on measured data from the North plant, 250 percent excess air is assumed to be provided by the forced-draft fans. There are, however, a number of points of air inleakage in the system which are assumed to contribute an additional 25 percent excess air. Therefore, the total gas flow is 77,600 scfm (72,300 dscfm), including all flue gas products.

Temperatures are monitored by thermocouples located in the roof of the ignition chamber and at the ESP inlet. Water sprays are automatically adjusted in the cooling chamber based on the temperature set point at the ESP inlet.

4.3.2.2 Emission Control System Design and Operation. As shown in Table 4.0-1, 3 of the 5 plants in this subcategory and 16 of the 24 refractory-wall MWC's are equipped with ESP's. Therefore, the most representative APCD for the model plant is an ESP. For the purposes of model development, the model is assumed to have an emission control system similar to the Montgomery County plants, with the exception that the model does not have sorbent injection. Furnace sorbent injection is unique to Montgomery County plants and is not representative of the population.

Each combustor at the model plant is equipped with a 3-field ESP with 53,000 square feet of collecting area. Current stack PM emissions are 0.03 gr/dscf. For the purposes of model development, it will be assumed that each combustor has its own stack, and that access/congestion constraints are moderate. A plot plan of the model plant is shown in Figure 4.3-4.

4.3.2.3 Environmental Baseline. Table 4.3-2 also presents baseline emissions data for the model plant. The Montgomery County plants do not have measured CDD/CDF emission data available. Due to the absence of an overfire air injection point downstream of the rotary kiln it is assumed

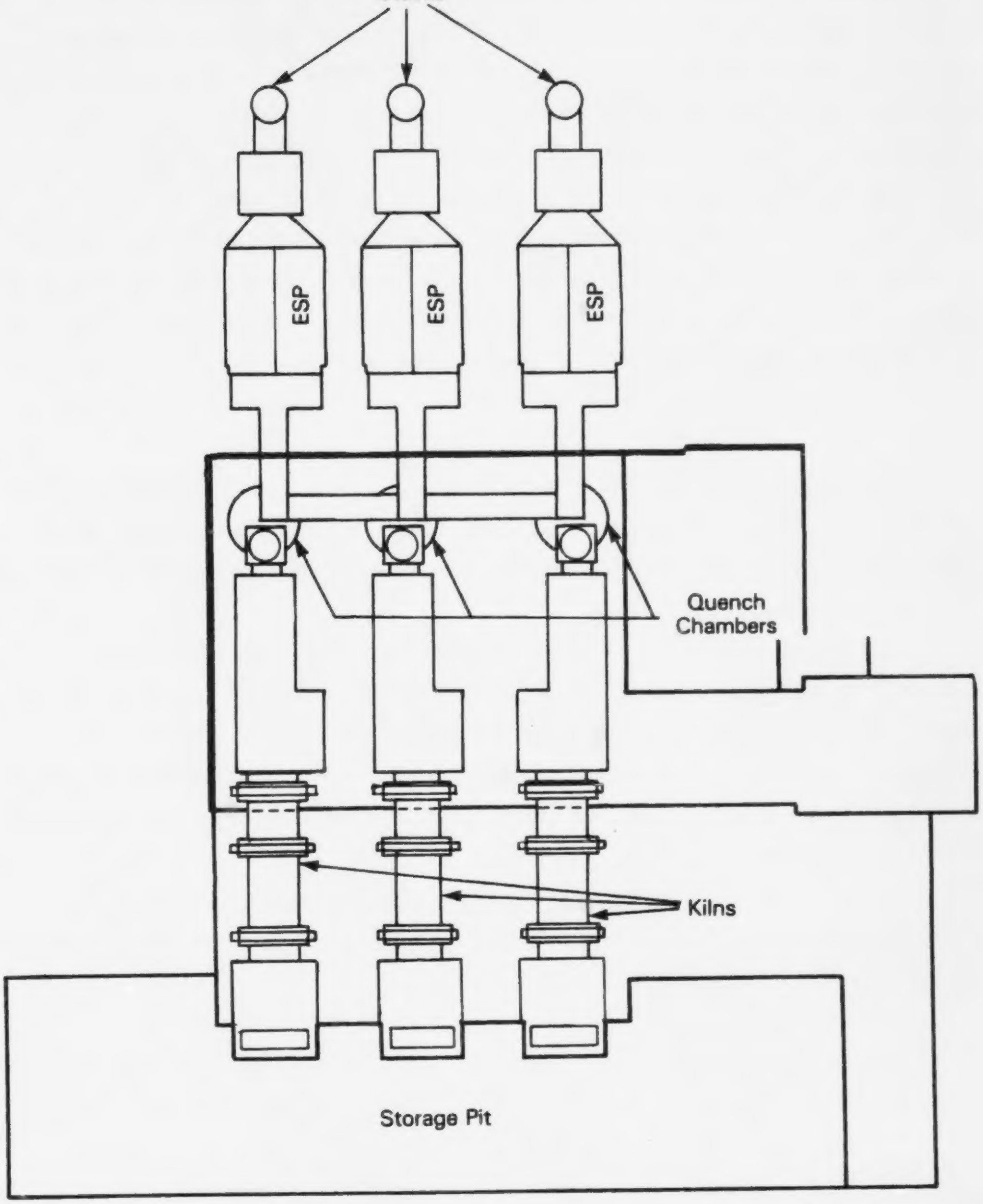

Figure 4.3-4. Model Plant Plot Plan.

that mixing of combustion gases is not optimized, and that CDD/CDF destruction is also not optimized. The high excess air levels also contribute to quenching of the combustion process, resulting in insufficient furnace temperatures. Assumed CDD/CDF baseline emission values are 4,000 ng/dscm corrected to 7 percent O_2.[2] These values do not reflect possible organics formation which may take place downstream of the combustor. Therefore, the model plant is assumed to have CDD/CDF emissions of 6,000 ng/dscm corrected to 7 percent O_2 at the stack.

Uncontrolled particulate emissions in mass burn waterwall combustors average 2.0 gr/dscf. Because excess air levels are higher in refractory-wall combustors, a greater amount of particulate is assumed to be carried out of the combustor than in waterwall MWC's. Therefore, an uncontrolled PM emission rate of 3.0 gr/dscf at 7 percent O_2 is assumed for baseline conditions.

Due to the poor mixing conditions and low operating temperatures assumed for the model plant, baseline CO emissions are assumed to be 500 ppmv. Uncontrolled HCl and SO_2 emissions are assumed to be 500 ppmv and 200 ppmv, respectively.

The model plant achieves 90 percent waste volume reduction and 70 percent weight reduction. These values are assumed based on visual observation during the site visit to North Montgomery County. Although ash disposal is free for the Montgomery County plants, an average disposal fee of $25/ton is assumed for the model plant to be more representative of the existing population.

4.3.3 Good Combustion and Exhaust Gas Temperature Control

The following sections describe combustion retrofits developed for the model plant described above.

4.3.3.1 Description of Modifications

Combustion Airflow Modifications. The following modifications to combustion airflows are included in the modified model plant:

- Excess air operating levels are reduced from 250 percent to 150 percent, allowing furnace operating temperatures to be maintained at 1,800°F in the fully mixed location and reducing the potential for particle entrainment. At 150 percent excess air the gas flow from the combustor is reduced to 49,300 scfm (46,300 dscfm).

- New overfire air ports are added in the overpass duct and in the mixing chamber to provide a source of mixing air. The exact specifications of these nozzles are to be determined using flow modeling studies. Approximately 110 percent of the theoretical air requirement (21,700 scfm) is supplied by the mixing air, with 35 percent theoretical air supplied at the overpass duct and 75 percent theoretical air supplied in the mixing chamber. In furnace CO profiling is used to verify mixing patterns.

- The sidewall ports are retained to supply wall cooling air. The combined total air supplied by the underfire air supply and the wall cooling air is 140 percent of the theoretical air requirement (27,600 scfm).

- A double guillotine airlock is installed at the bottom of the supply plenum/hopper beneath the ignition grate, providing a seal to the air supply and eliminating this source of air inleakage. However, inleakage downstream of the combustor results in stack flows equivalent to 175 percent excess air (53,000 dscfm).

The reconfigured combustion air design is illustrated in Figure 4.3-5.

Auxiliary Fuel. The modified model plant has two auxiliary fuel burners, sized to provide a total heat input equal to 60 percent of full unit load (67.5 MM Btu/hr). One burner is located above the drying grates on the roof of the ignition chamber. The second burner is located downstream of the overfire air nozzles in the mixing chamber. The burners are used during start-up, shutdown, and episodes of low furnace temperature and high CO.

Combustion Control. In the baseline configuration the combustion control scheme is entirely manual. As part of the combustion modifications improved controls are necessary. Because there is no steam production, the primary variables to include in the control scheme are excess oxygen and temperature. The revised controls include an oxygen trim loop which automatically adjusts the amount of underfire air in response to a signal from an oxygen controller. A temperature controller is included with an alarm at high and low setpoints. Overfire air rates are kept constant. Adjustments in overfire air and kiln grate speeds will be made manually, if needed.

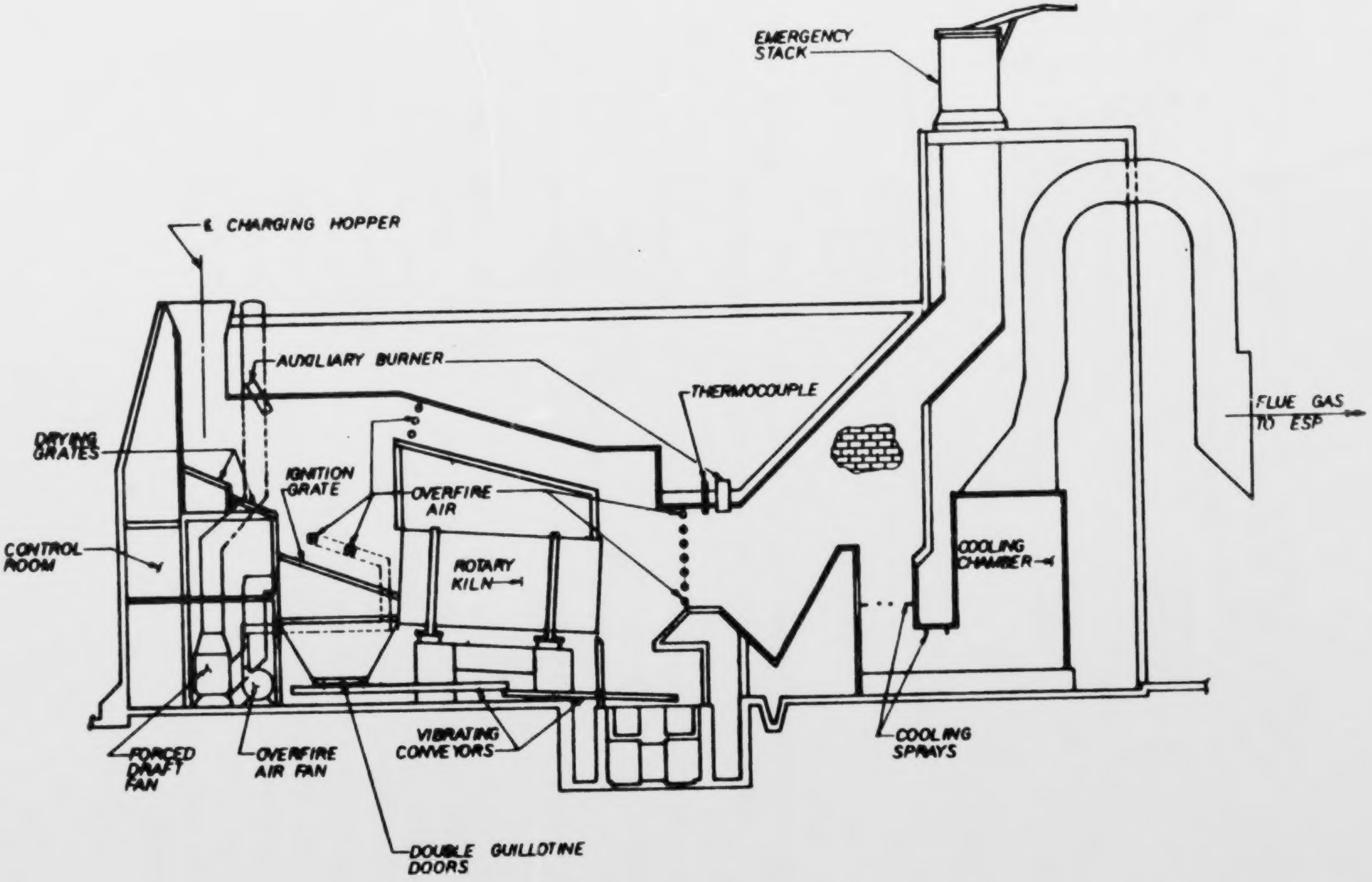

Figure 4.3-5. Combustor Profile Showing Combustion Modifications.

Verification. Verification of good combustion consists of insuring that the system is operating according to its design. There are a number of operating parameters that must be monitored and controlled in order to achieve this objective. At a minimum, refractory-wall combustors must continuously monitor:

1) underfire and overfire air flows (pressure settings)
2) combustor draft
3) O_2 (excess air) and CO in the flue gas
4) combustor temperature.

Underfire and overfire air flows are monitored by maintaining specified pressures in supply headers. Combustor draft is maintained by a variable-speed ID fan. Flue gas O_2 and CO are measured at the same location in the system so that the CO reading can be corrected to a standard value, such as 7 percent O_2. Combustor temperature requirements are specified at a location where the mixing process is completed, just downstream of the last point of overfire air injection.

Temperature Control Downstream. The set point on the cooling water sprays should be lowered so as to maintain the ESP inlet temperature at 450°F.

Retrofit Considerations. It is estimated that total facility downtime for installation of the combustion modifications will be one week per unit.

4.3.3.2 Environmental Performance. As a result of applying the above described modifications to the model plant, baseline CDD/CDF emissions are estimated to be reduced to 500 ng/dscm.[2] Emissions of CO are reduced to 150 ppmv. No change in uncontrolled emissions of PM, HCl, or SO_2 can be anticipated as a result of these modifications. The modifications also have no effect on solid waste disposal quantities.

4.3.3.3 Costs. Capital costs of the combustion retrofit options are presented in Table 4.3-3. Annual operating and maintenance costs are presented in Table 4.3-4. The total capital cost of the modifications is $1,130,000. Downtime cost is $109,000. Annualized capital and downtime costs are $163,000. Total annualized costs, including operating and maintenance costs, are $429,000.

TABLE 4.3-3. PLANT CAPITAL COSTS FOR COMBUSTION RETROFITS
(Three units of 300 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Flow modeling and thermal analysis	125
Overfire air ducting, dampers, positioners and nozzles	39
Underfeed and Overfeed air flow monitors	32
Gas pipeline (1/2-mile)	50
Auxiliary fuel burners[a]	244
O_2 and CO monitors with readouts and integrators	135
CO profiling	10
O_2 trim controls on forced draft fans	38
Underfire air plenum/hopper	79
Total	752
INDIRECT COSTS AND CONTINGENCY:	376
TOTAL CAPITAL COSTS	1,130
DOWNTIME COST	109
ANNUALIZED CAPITAL COSTS	163

[a] One per combustor. Includes controller and flame detectors.

TABLE 4.3-4 PLANT ANNUAL COSTS FOR COMBUSTION RETROFIT
(Three units of 300 tpd each)

Item		Costs ($1000)
DIRECT COSTS:		
Natural gas consumption[a]		87
Operating labor		0
Maintenance labor		42
Maintenance materials		42
	Total	171
INDIRECT COSTS:		
Overhead		50
Taxes, Insurance, Administration		45
Annualized Capital and Downtime		163
	Total	258
TOTAL ANNUALIZED COSTS		429

[a] 12 start-ups/unit/year.

4.3.4 Best Particulate Control

The existing gas conditioning chambers reduce baseline uncontrolled PM loadings from 3.0 gr/dscf at the combustor outlet to 1.0 gr/dscf at the outlet of the chambers. Under baseline combustion conditions, the existing ESP's reduce PM emissions from 1.0 gr/dscf to 0.03 gr/dscf at the outlet. This emission level is below the level (0.05 gr/dscf) defined by this study as good control; thus, no equipment modifications are required for good PM control for the model plant.

Under good combustion conditions, reduced flue gas volume will also result in improved ESP performance, and the existing ESP's will reduce PM to 0.01 gr/dscf. Thus, there are also no particulate control equipment modifications required for best particulate control (0.01 gr/dscf) for this model plant.

4.3.5 Good Acid Gas Control

4.3.5.1 Description of Modifications. For good acid gas and CDD/CDF control, dry sorbent will be injected into each combustor through the overfire air ducts. The water quench system in the cooling chamber will remain in place, but an additional 30 gpm will be used to cool the flue gas from $550^{\circ}F$ to $350^{\circ}F$ under baseline combustion conditions. With good combustion in place, 22 gpm will be used. New equipment for the site includes a sorbent storage silo with baghouse, a pneumatic sorbent conveying system, six sorbent feed bins (two for each combustor), and two pneumatic injection nozzles for each combustor.

Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full load, this will require a sorbent injection rate of 340 lb/hr per combustor. In addition, ESP plate area necessary to reduce PM emissions to 0.01 gr/dscf (best PM control) will be added. Under good combustion, a 13,300 square feet addition of area will be required. With baseline combustion 36,200 feet is needed. The additional area will be added as an ESP in series behind the existing ESP on each unit. Installation will also require an additional 150 feet of duct, and thus replacement of the ID fan, for each unit. The project also includes new monitoring equipment for HCl, SO_2, and CO_2.

Figure 4.3-6 shows the planned equipment arrangement. Work on each combustor can proceed while the other two combustors continue to operate. This plan would limit combustor downtime to approximately 1 month for each unit.

4.3.5.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 98 percent. Acid gas emission reductions are estimated at 50 percent for HCl and 50 percent for SO_2. Particulate emissions will be reduced from 0.03 to 0.01 gr/dscf.

Application of sorbent injection technology will add 5,300 tons/year of recovered sorbent and fly ash to the baseline waste disposal requirements for the plant.

4.3.5.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 4.3-5. Total capital cost is estimated to be \$9,410,000 for baseline combustion practices and \$7,250,000 with good combustion. Downtime cost is \$437,000 in both cases.

Annual operating and maintenance costs and annual indirect costs are present in Table 4.3-6. Major direct costs are for lime and maintenance of monitors. Electricity costs are also substantially higher than baseline as a result of the additional ESP plate area and larger ID fans. The total annualized cost (including capital recovery and downtime) is \$2,890,000 per year with baseline combustion and \$2,450,000 with good combustion practices.

4.3.6 Best Acid Gas Control

4.3.6.1 Description of Modifications. To achieve greater reduction in SO_2, HCl, and CDD/CDF emissions, a new spray dryer/fabric filter system will be installed on each combustor after the conditioning chamber. Lime slurry will be introduced in each spray dryer at a 2.5:1 molar calcium-to-acid gas ratio. Lime for each combustor will be slurried in the 37 gpm needed to cool the flue gas from 550^0 to 300^0F under baseline. With good combustion in place, 27 gpm will be needed. A fabric filter with 56,200 net square feet of cloth (net air-to-cloth ratio of 4:1) will be installed following each spray dryer if baseline combustion is practiced; the required area is 41,800 square feet if good combustion is in place. The increased pressure drop of fabric filters over ESP's will require a new ID fan for each unit as well. New monitoring instruments for HCl, SO_2, CO_2 and opacity will also be installed.

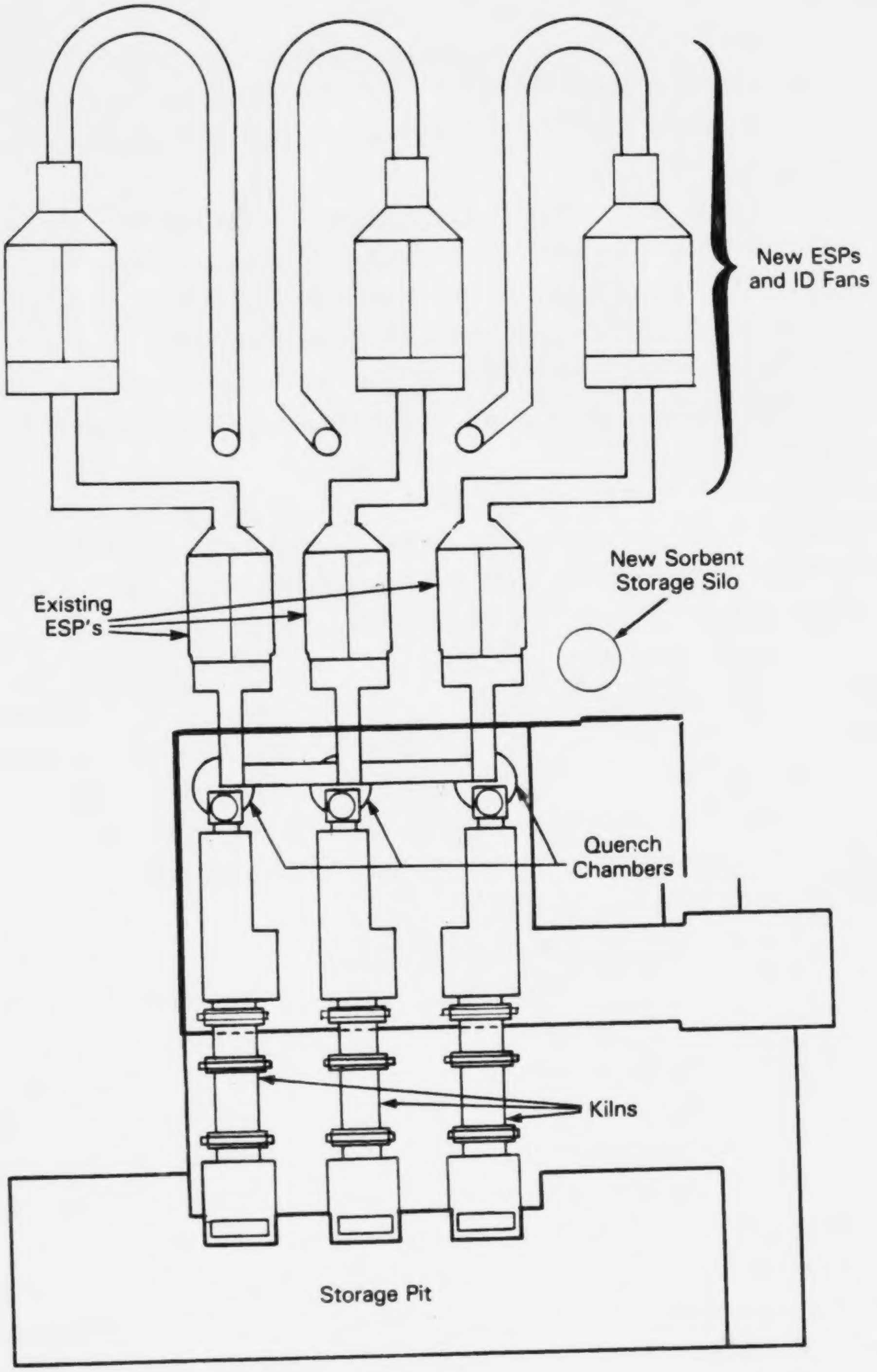

Figure 4.3-6. Plot Plan of Sorbent Injection Equipment Arrangement

TABLE 4.3-5. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ESP (Three units of 300 tpd each)

Item	Cost ($1,000) Baseline Combustion Practices	Cost ($1,000) Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment Cost	674	674
Access/Congestion Cost	67	67
Particulate Control		
Equipment Cost	3,210	2,150
Access/Congestion Cost	802	538
New Flue Gas Ducting		
Ducting Cost	295	255
Access/Congestion Cost	74	64
Other Equipment		
Fans	959	722
Stacks	0	0
Demolition/Relocation	0	0
Total	6,080	4,470
Indirect Costs and Contingencies	2,560	2,010
Monitoring Equipment[b]	771	771
TOTAL CAPITAL COST	9,410	7,250
DOWNTIME COST	437	437
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	1,300	1,010

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[a] Based on moderate access/congestion.

[b] Turnkey.

TABLE 4.3-6. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ESP (Three units of 300 tpd each)

Item		Cost ($1,000) Baseline Combustion Practices	Cost ($1,000) Good Combustion Practices
DIRECT COSTS:			
Operating Labor		72	72
Supervision		32	32
Maintenance Labor		20	20
Maintenance Materials		96	77
Electricity		97	58
Water		11	8
Lime		326	326
Waste Disposal		133	133
Monitors		309	309
	Total	1,100	1,040
INDIRECT COSTS:			
Overhead		152	141
Taxes, Insurance, and Administration		342	256
Capital Recovery and Downtime		1,300	1,010
	Total	1,790	1,410
TOTAL ANNUALIZED COST		2,890	2,450

The proposed equipment arrangement is shown in Figure 4.3-7. The new equipment will be located primarily behind the existing stacks. The 250 feet of new ductwork will tied in just ahead of the ESP's, allowing them to be deactivated and left in place. The existing stacks will also be reused under this arrangement. The new lime receiving, storage and slurry area will serve all three spray dryers.

Location of new equipment behind the existing stack will allow continued combustor operation during construction. Downtime for tie-in is expected to be approximately 1 month.

4.3.6.2 Environmental Performances. Total CDD/CDF emission reductions of 99 percent or to 5 ng/dscm (whichever is higher), is expected. Emissions of particulate matter will be reduced from 0.03 gr/dscf to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl.

Solid waste will be increased with this technology relative to baseline amounts. The total increases in solid waste (both sorbent and fly ash) is 4,690 tons per year for the plant.

4.3.6.3 Cost. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 4.3-7. Total capital cost is estimated to be $34,300,000 and $29,400,000 for baseline and good combustion, respectively. Downtime cost is $437,000 for both cases.

Annual operating and maintenance costs and annual indirect costs are presented in Table 4.3-8. Major operating expenses are for maintenance materials and increased electricity use by the larger ID fan needed because of the increased pressure drop across the fabric filters. Total annualized cost of best acid gas control (including capital recovery and downtime) is $8,750,000 per year for baseline, and $7,550,000 with good combustion practices.

4.3.7 Summary of Control Options

4.3.7.1 Description of Control Options. The control technologies described in the previous sections have been combined into seven retrofit emission control options. These options are discussed in detail in Section 3.0. Table 4.3-9 summarizes the combustion, temperature, particulate, and acid gas control technologies described in Sections 4.3.3

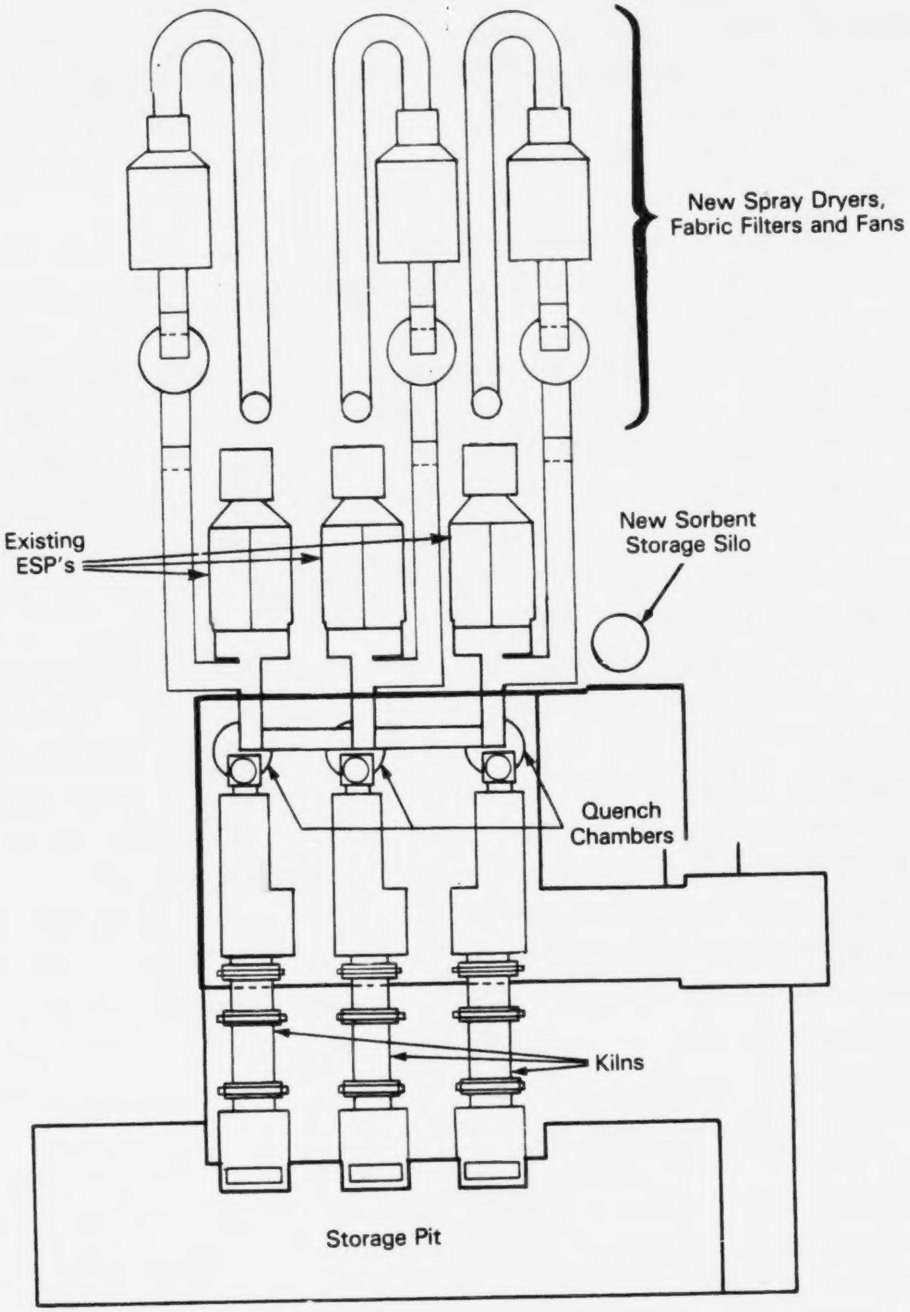

Figure 4.3-7. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement

TABLE 4.3-7. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 300 tpd)

Item	Cost ($1,000)	
	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Acid Gas and Particulate Control		
Equipment Cost	15,300	3,290
Access/Congestion Cost	3,840	3,290
New Flue Gas Ducting		
Ducting Cost	534	461
Access/Congestion Cost	134	115
Other Equipment		
Fans	1,130	849
Stacks	0	0
Demolition/Relocation	0	0
Total	20,900	17,900
Indirect Costs	6,920	5,910
Monitoring Equipment[a]	859	859
Contingency	5,580	4,761
TOTAL CAPITAL COST	34,300	29,400
DOWNTIME COST	437	437
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	4,570	3,930

[a] Turnkey.

TABLE 4.3-8. PLANT ANNUAL COST OF SPRAY DRYER WITH FABRIC FILTER (Three units of 300 tpd each)

Item	Cost ($1,000) Baseline Combustion Practices	Cost ($1,000) Good Combustion Practices
DIRECT COSTS:		
Operating Labor	144	144
Supervision	22	22
Maintenance Labor	79	79
Maintenance Materials	584[a]	480[b]
Electricity	714	534
Compressed Air	102	76
Water	27	20
Lime	271	270
Waste Disposal	175	174
Monitors	322	322
Total	2,440	2,120
INDIRECT COSTS:		
Overhead	399	362
Taxes, Insurance, and Administration	1,340	1,140
Capital Recovery and Downtime	4,570	3,930
Total	6,310	5,430
TOTAL ANNUALIZED COST	8,750	7,550

[a] Includes $164,000 for bag replacement.

[b] Includes $122,000 for bag replacement.

TABLE 4.3-9 SUMMARY OF CONTROL OPTIONS FOR GRATE/ROTARY KILN MASS BURN REFRACTORY-WALL COMBUSTOR

Control Option Description	Combustion Modifications	Temperature Control	Particulate Matter Control		Acid Gas Control		
			Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion and Temperature Control	X	X					
3. Best PM Control with Combustion and Temperature Control	X	X					
4. Good Acid Gas Control and Best PM Control with Temperature Control and Baseline Combustion		X		X		X	
5. Good Acid Gas Control and Best PM Control with Combustion and Temperature Control	X	X		X		X	
6. Best Acid Gas Control and Best PM Control with Temperature Control and Baseline Combustion		X			X		X
7. Best Acid Gas Control and Best PM Control with Combustion and Temperature Control	X	X			X		

through 4.3.6 that were combined for each of the control options. It should be noted that because good PM control is already achieved by the model plant at baseline, Option 1 and Option 2 are identical. Since good combustion control also reduces PM emissions to 0.01 gr/dscf, Option 3 is also the same as Options 1 and 2.

4.3.7.2 Environmental Performance. The performance of each control option is summarized in Table 4.3-10. For each pollutant the table presents both the pollutant concentrations and annual emissions. The greatest reductions in acid gases and total CDD/CDF are achieved with the spray dryer/fabric filter systems. The next most effective control for these pollutants is dry sorbent injection. Combustion control provides similar control of CDD/CDF to duct sorbent injection, but also reduces CO emissions and lowers flue gas volumes, resulting in reduced PM emissions as well.

4.3.7.3 Costs. The total annualized cost of each option is presented in Table 4.3-11. The most effective control options are also the most costly, with the exception of the options where APCD's are combined with good combustion practices. For Options 5 and 7, the cost of combustion modifications is recovered by the reduced cost of PM control equipment resulting from reduced flue gas volume. Thus, Options 5 and 7 are less costly overall than the same type APCD's installed with baseline combustion gas volumes (Options 4 and 6).

4.3.7.4 Energy Impacts. Table 4.3-12 presents a summary of the energy impacts associated with the control options. The incremental energy use shown includes the electrical savings realized by not operating the existing ESP under Options 6 and 7. The auxiliary fuel use is calculated from 12 startups and shutdowns per year with auxiliary burners providing 60 percent of the thermal load.

TABLE 4.3-10 ENVIRONMENTAL PERFORMANCE SUMMARY FOR GRATE/ROTARY KILN REFRACTORY-WALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Three units of 300 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	6000	500	500	500	1000	125	40	5
Mg/yr^c	7.0E-3	5.6E-4	5.6E-4	5.8E-4	1.2E-3	1.4E-4	5.0E-5	7.0E-6
% Reduction vs. Baseline	--	92	92	92	83	98	99.3	99.9
CO Emissions								
(ppmv)	500	150	150	150	500	150	500	150
Mg/yr	730	216	216	216	730	216	730	216
% Reduction vs. Baseline	--	70	70	70	0	70	0	70
PM Emissions								
(gr/dscf)	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	80	27	27	27	27	27	27	27
% Reduction vs. Baseline	--	0	0	67	67	67	67	67
SO_2 Emissions								
(ppmv)	200	200	200	200	100	100	19	19
Mg/yr	667	667	667	667	334	334	63	63
% Reduction vs. Baseline	--	0	0	0	50	50	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	250	250	15	15
Mg/yr	951	951	951	951	476	476	27	27
% Reduction vs. Baseline	--	0	0	0	50	50	97	97
Total Solid Waste								
(tons/day)	270	270	270	270	286	286	291	291
Mg/yr	81,800	81,800	81,800	81,800	86,600	86,100	88,200	88,200
% Increase vs. Baseline	--	0	0	0	6	6	8	8

[a] All flue gas concentrations are reported on a 7% O_2 basis. Normal and standard conditions are 1 atmosphere and 70°F.

TABLE 4.3-11 COST SUMMARY FOR GRATE/ROTARY KILN REFRACTORY-WALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 300 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	1,130	1,130	1,130	9,410	8,380	34,300	30,500
Downtime Cost	109	109	109	437	437	437	437
Annualized Capital and Downtime Cost	163	163	163	1,300	1,160	4,570	4,080
Direct O & M Cost	171	171	171	1,100	1,210	2,440	2,290
Total Annual Cost	429	429	429	2,890	2,860	8,750	7,960
Cost Effectiveness ($/ton MSW)	1.43	1.43	1.43	9.63	9.53	29.20	26.50
Facility Downtime (Months)	0.25	0.25	0.25	1	1	1	1
Total Compliance Time (Months)	5	5	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs given in December 1987 dollars.

TABLE 4.3-12. ENERGY IMPACTS FOR GRATE/ROTARY KILN MASS BURN REFRACTORY-WALL MWC CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	1.5E10
2	0	1.5E10
3	0	1.5E10
4	2,100	0
5	1,260	1.5E10
6	15,500[b]	0
7	11,600[b]	1.5E10

[a] Incremental use from baseline.

[b] Excludes the electrical credit for not operating the ESP's.

4.4 REFERENCES

1. Lamb, L., Radian Corporation, Schindler, P., Energy and Environmental Research Corporation. Trip Report - Retrofit Control Site Evaluation at the Philadelphia Northwest Incinerator and East Central Facility. January 19, 1989.

2. Schindler, P. EER Corporation. Combustion Control Memorandum - Existing MWCs. October 31, 1988.

3. Schindler, P., Energy and Environmental Research Corporation, and Emmel, T., Radian Corporation. MWC Site Evaluation - Sheboygan, WI Incinerator March 25, 1988.

4. Epner, E., Radian Corporation, and Schindler, P., Energy and Environmental Research Corporation. Trip Report - Retrofit Control Site Evaluation at the North Dayton and South Dayton Municipal Waste Incinerators. March 22, 1988.

5. ASTM. A588-J. C, 0.19%; Cu, 0.25-0.4%; Mn, 0.8-1.25%; Pb, 0.04% max.; S, 0.05% max; Si, 0.3-0.65%; Ni, 0.4% max; Cr, 0.4-0.65%; V, 0.02-0.1%.

5.0 MASS BURN WATERWALL COMBUSTORS

One of the predominant technologies in the existing population of MWC's is the mass burn waterwall design. This section describes the current design and operation of newer waterwall combustors and identifies features in the design and operation which minimize air emissions.

The existing population of mass burn waterwall MWC's consists of 24 operating plants (56 individual units). Table 5.0-1 lists the mass burn waterwall plants operating or in start-up as of 1988. Included in the table are number of units, unit capacity, year of start-up, and APCD in place at each plant. Individual combustor design capacities range from 50 to 1000 tons/day of MSW. The table is divided into three sections, representing large mass burn waterwalls with individual capacities of more than 600 tpd, mid-size units with individual capacities between 250 and 600 tpd, and small units with individual capacities of less than 250 tpd. Nineteen plants in this category use ESP's for particulate control. One plant uses dry lime injection into the furnace followed by an ESP and one plant uses dry lime injection into a duct followed by a fabric filter. Five other plants use a spray dryer followed by either a fabric filter or an ESP. Most of these plants are publicly owned and operate on a 24-hours/day, 7-days/week schedule.

Typical mass burn waterwall systems are shown in Figures 5.1-1, 5.2-1, 5.2-2, and 5.2-3. Unprocessed waste (with large, bulky, non-combustibles removed) is delivered by an overhead crane to a feed hopper from which it is fed into the combustion chamber. Earlier mass burn designs utilized gravity feeders, but it is more typical today for feeding to be accomplished by single or dual hydraulic rams that operate on a set frequency. The ram frequency is usually a manual setting, but some newer facilities are incorporating ram feeder speed into the automatic combustion control system.

Nearly all modern conventional mass burn facilities utilize reciprocating grates to move the waste through the combustion chamber. The grates typically include two or three separate sections where designated stages in the combustion process occur. For example, the initial grate section is referred to as the drying grate, where the moisture content of the waste is removed

TABLE 5.0-1. EXISTING MASS BURN WATERWALL COMBUSTORS

Plant/Location	No. of Units	Unit Size (tpd)	Year of Start Up	Air Pollution Control Device
Millbury, MA	2	750	1988	Dry Scrubber/ESP
Pinellas County, FL	3	1000	1983	Electrostatic Precipitator
North Andover, MA	2	750	1985	Electrostatic Precipitator
Saugus, MA	2	750	1975	Electrostatic Precipitator
Westchester County, NY	3	750	1984	Electrostatic Precipitator
Baltimore, MD (RESCO)	3	750	1985	Electrostatic Precipitator
Bridgeport, CT	3	750	1988	Dry Scrubber/Fabric Filter
Chicago, IL (NW)	4	400	1970	Electrostatic Precipitator
Nashville, TN	3	2 @ 360 1 @ 400	1974 1986	Electrostatic Precipitator Electrostatic Precipitator
Hillsborough County, FL	3	400	1987	Electrostatic Precipitator
Tulsa, OK	2	375	1986	Electrostatic Precipitator
Harrisburg, PA	2	360	1973	Electrostatic Precipitator
Alexandria, VA	3	325	1987	Furnace Lime Injection/ Electrostatic Precipitator
Commerce, CA	1	300	1987	Dry Scrubber/Fabric Filter
Marion County, OR	2	275	1986	Dry Scrubber/Fabric Filter
Norfolk Naval Station, VA	2	180	1967	Electrostatic Precipitator
Glen Cove, NY	2	125	1983	Electrostatic Precipitator
Hampton, VA	2	100	1980	Electrostatic Precipitator
New Hanover County, NC	2	100	1984	Electrostatic Precipitator
Claremont, NH	2	100	1987	Duct Lime Inj./Fabric Filter
Jackson County, MI	2	100	1987	Dry Scrubber/Fabric Filter
Key West, FL	2	75	1987	Electrostatic Precipitator
Harrisonburg, VA	2	50	1982	Electrostatic Precipitator
Olmstead County, MN	2	100	1988	Electrostatic Precipitator

prior to ignition. The second grate section is the burning grate, where the majority of active burning takes place. The third grate section is referred to as the burnout or finishing grate, where remaining combustibles are burned. Smaller units may include two rather than three individual grate sections. In a typical mass burn waterwall system, bottom ash is discharged from the finishing grate into a water-filled ash quench pit. Dry ash systems have been used in some designs, but are not widespread.

Combustion air is added to the waste from beneath the grate by way of underfire air plenums. The majority of mass burn waterwall systems supply underfire air to the individual grate sections through multiple plenums. The ability to control heat release from the waste bed is enhanced by separately controllable underfire air supplies. The lower furnace is generally lined with castable refractory such as silicon carbide, to prevent excessive heat removal in the lower furnace by waterwall tubes.

As the waste bed burns, additional air is required to oxidize fuel-rich gases and complete the combustion process. Overfire air is injected through rows of high-pressure nozzles (usually 2 to 3 inches in diameter). Properly designed and operated overfire air systems are essential for good mixing and burnout of organics in the flue gas. Overfire air jets should provide complete coverage and penetration of the furnace cross-section. Proper overfire air system design usually requires flow modeling studies, but may be accomplished by ensuring design consistency with systems for which good performance has been verified.

Typically, mass burn waterwall MWC's are operated with 80 to 100 percent excess air. Normally 25 to 40 percent of total air is supplied as overfire air and 60 to 75 percent as underfire air. These are nominal ranges that may vary between specific designs. Continuous oxygen monitors are typically located at the exit of the boiler or economizer to verify the excess air operating levels.

Most heat recovery systems incorporate temperature monitoring at various locations through the system. One reference point is the furnace exit gas temperature, where flue gases leave the radiant furnace and enter the superheater and convective passes of the boiler. Another typical location is at the boiler or economizer outlet. Typical superheater inlet temperatures are in the range of 1400 to 1600°F. Economizer outlet temperatures vary from

350 to 600°F based on the amount of heat removal through the system.

The most common combustion control system used in mass burn waterwall technology utilizes automatic feedback from steam flows or pressures to underfire air. The underfire air flowrate automatically varies to maintain desired steam level setpoints. Some more recent designs incorporate oxygen trim loops, ram feeder speed controls, grate speed controls, and temperature control loops.

Guidelines for minimizing emissions of trace organics have been developed for mass burn waterwall combustors.[1] A list of design, operation/control, and verification components associated with the guidelines is presented in Table 5.0-2. The basic guidelines require that:

- stable stoichiometries be maintained through proper distribution of fuel and combustion air,
- good mixing be achieved at a sufficiently high temperature to adequately destroy trace organic species, and
- the design and operation of the system be verified through monitoring or performance tests.

The majority of existing mass burn waterwall MWC's employ most of the design features of good combustion. This is due in part to the fact that most of these plants are less than five years old and incorporate refinements in technology that have resulted in many design improvements. The following discussion focuses on elements of concern to mass burn waterwall systems.

Combustion Air

A major area of concern in older mass burn waterwall systems is the design of overfire air systems. Several existing facilities have undertaken retrofits to improve the design in these systems. Improvements in the performance of overfire air systems can be verified by the relatively low levels of organic and CO emissions, which indicates good mixing and oxidation of combustion gases with overfire air.

Auxiliary Fuel

All existing facilities in this subpopulation are expected to be able to meet the temperature design requirement, and multiple underfire air plenums with separate controls are in place at most operating facilities. Although new MWC's are expected to have auxiliary fuel firing capabilities, many of the older units do not. One facility built in 1984 (New Hanover County, NC) is

TABLE 5.0-2 COMPONENTS OF GUIDELINES - GOOD COMBUSTION PRACTICES FOR MINIMIZING TRACE ORGANIC EMISSIONS FROM MASS BURN MWC's

Element	Component
Design	Temperature at fully mixed height
	Underfire air control
	Overfire air capacity
	Overfire air injector design
	Furnace exit gas temperature
Operation/Control	Excess Air
	Turndown restrictions
	Start-up procedures
	Use of auxiliary fuel
Verication	Oxygen in flue gas
	CO in flue gas
	Furnace temperature
	Temperature at APCD inlet
	Adequate air distribution

not equipped with auxiliary fuel, although a planned expansion reportedly will include natural gas burners in a new unit.

Operation/Control

The operation/control elements specified in Table 5.0-2 are also largely in place in most operating units. A few exceptions may be low load operating limits and conditions of auxiliary fuel use. The mass burn waterwall units reportedly operate at close to design load whenever possible, and more facilities are becoming electrical generators rather than simply following load demand of a steam customer. For other facilities, load levels can be dictated by waste availability as well as steam demand, but load reductions for mass burn waterwall systems are more likely due to the latter. Those systems without auxiliary fuel must start-up and shutdown on waste alone. However, mass burn waterwall systems typically operate continuously with as few unscheduled shutdowns as possible.

All mass burn waterwall systems are expected to be equipped with oxygen monitors and thermocouples for temperature measurements. These are necessary requirements for ensuring proper boiler operation. However, CO monitors are less likely to be in place in most operating units, with the exception of facilities where State requirements include CO monitoring. In addition, most existing units are not expected to have performed CO profiling studies to establish combustion air distribution patterns. Therefore, verification of proper air distributions in existing systems are largely based on continuous oxygen and temperature measurements and visual observation of waste burning conditions.

Temperature Control

As discussed in Section 4.0, recent data suggest that CDD/CDF formation may occur downstream at temperatures between 500 and 600^{0}F. This is a typical operating temperature for many ESP's in the waste combustion industry. Based on available data it appears that formation does not occur at temperatures of 450^{0}F or less. Therefore, existing systems must attempt to minimize retention time of flue gases in the range of 500 to 600^{0}F by lowering ESP operating temperatures.

5.1 LARGE MASS BURN WATERWALL COMBUSTOR

This section presents the retrofit case study results for a large mass burn waterwall municipal waste combustor (MWC). This subcategory comprises mass burn waterwall combustors with individual combustor capacities of more than 600 tpd. As shown in Table 5.0-1, there are 7 known plants in this subcategory. Section 5.1.1 presents a description of the Saugus MWC plant, which was visited in order to gather information for model development. Section 5.1.2 presents a description of the model plant. Section 5.1.3 through 5.1.7 detail the retrofit modifications, estimated performance, and costs associated with various control options. Section 5.1.8 presents a summary of control options, which are discussed in more detail in Section 3.0 of this report.

5.1.1 Description of Saugus Plant[2]

The Saugus facility consists of two mass burn waterwall combustors. Each is rated at 750 tons per day of municipal solid waste. Table 5.1-1 presents design and operating data for the plant. The plant was started up in October 1975, and currently serves 19 Boston North Shore communities. The project was financed by industrial revenue bonds (75 percent) and private equity (25 percent). All steam is used on site to generated electricity which is sold to New England Power Company. Figure 5.1-1 illustrates the general system configuration.

5.1.1.1 Combustor Design and Operation. This plant was the first large Von Roll design built in the U.S., and is typical of the type of system supplied by Von Roll in the mid-1970's. There is no ram feeder. Fuel feeding is by gravity and is controlled by the speed of the first grate. The facility burns a combination of municipal and commercial waste. Currently, only about 15 percent of the refuse burned is commercial. No auxiliary fuel is available. The units operate continuously, 7-days/week.

There are three reciprocating grates in each combustor. They are designated as the feed grate, burning grate, and burnout grate. There are 1-meter vertical steps from the feed grate to the burning grate, and from the burning grate to the burnout grate. This is not typical of the other

TABLE 5.1-1. SAUGUS, MASSACHUSETTS DESIGN DATA

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 2
Combustor Unit Capacity	- 750
Grate Manufacturer	- Van Roll
Boiler Manufacturer	- Dominion Bridge
Emission Controls:	
Type	- Electrostatic Precipitator
Manufacturer	- Wheelabrator-Frye
Number of Fields	- 2
Inlet Design Particulate Loading	- 0.2 to 2.0 gr/dscf
Operating Temperature	- 428 to 550°F
Design Collection Efficiency	- 97.5 percent
Particulate Emission Limit	- 0.05 gr/dscf
Gas Flow	
Original Design	- 240,000 acfm
Revised Design	- 200,000 acfm
Operating	- 180,000 acfm
Total Plate Area	- 41,745 ft^2
SCA at 180,00 acfm	- 232
Residence Time	- 5.8 seconds

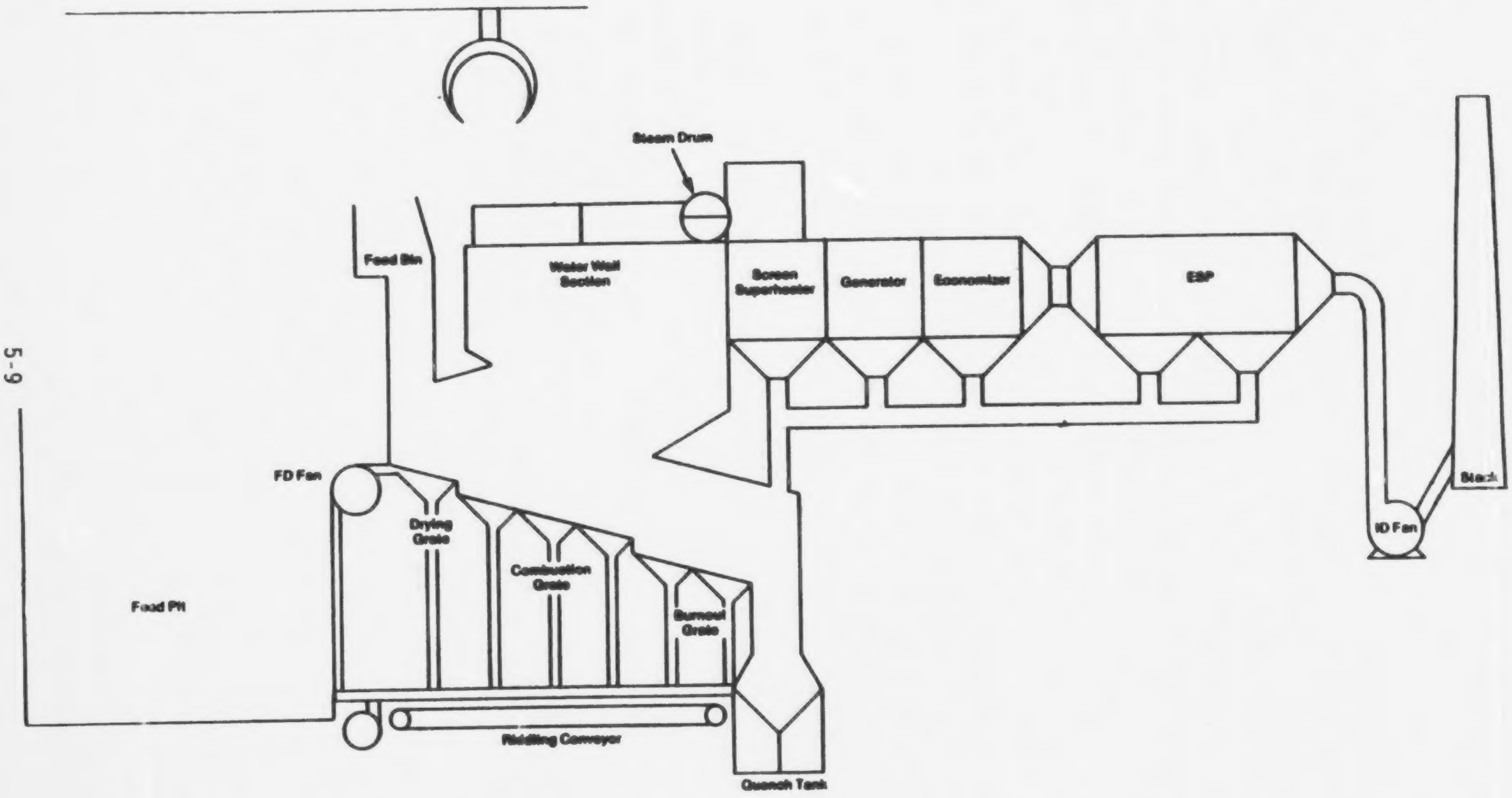

Figure 5.1-1. General System Diagram of Saugus MWC Plant

plants of this design type, which have eliminated the use of large grate steps in their design. The stepped grates may contribute to flashing of the waste as it tumbles from one section to another, making combustion control more difficult.

Bottom ash is discharged to a wet quench system. The bottom ash is then trommeled, and ferrous materials are separated and recovered. The remaining bottom ash is then combined with fly ash and disposed of in an adjacent landfill. The landfill is owned by DeMatteo Construction, which has a 50 percent interest in the facility.

There are six pairs of air plenums supplying underfire air--three pairs are located beneath the burning grate and three pairs beneath the burnout grate. The underfire air flows are adjusted manually to each plenum. Adjustments are made based on burning conditions and waste characteristics. The feed grate is equipped with two siftings hoppers but not an underfire air supply. The air is not preheated. Underfire air is generally 55 to 70 percent of total air.

The overfire air system was redesigned as part of a larger modification implemented in the late 1970's. There are two rows of 3-inch diameter nozzles on the combustor front wall and one row of 3-inch nozzles on the rear wall. There are nine nozzles in the front wall upper row, spaced 28.5 inches apart. The lower row on the front wall contains ten nozzles spaced 28.5 inches apart. There are fifteen nozzles on the rear wall, spaced 18.75 inches apart. Side wall overfire air nozzles are also in place, but are not currently used. Overfire air nozzle pressures are measured in the supply headers. Jet penetration is verified by calculation using the nozzle pressure and by visual observation of the furnace. The owner/operator also stated that CO profiling and flow modeling are used to establish overfire air firing patterns, and that they consider both of these activities to be necessary at new facilities.

The furnace design excess air level is 100 percent (200 percent theoretical air). Changes in excess air are made by varying underfire air and holding overfire air constant.

Each combustor is equipped with a Dominion Bridge boiler rated at 188,500 lb/hr of 675 psi, 875^{O}F steam. Current operating conditions are 165,000 lb/hr, 650 psi, 850^{O}F. Soot is removed from the boiler tubes by mechanical rapping, which takes place for five minutes once every hour. Electricity is generated in General Electric steam turbine generator sets, with a total capacity of 40 MW.

In addition to redesigning the overfire air system, additional combustor and boiler modifications have been made at Saugus. Arches have been added in the front and rear walls, and the upper combustion chamber has been reconfigured. In addition, the superheater section was moved further downstream and screen tubes were added prior to the superheater. After experimenting with tube materials the superheater tubes were replaced with Inconel tubes.

Although the newer Wheelabrator plants typically use a fully automatic computerized combustion control system, the Saugus plant uses a pneumatic type control system. Air flows and grate speeds are adjusted automatically based on steam pressure. In addition, a number of operating variables are monitored and serve as a guide to good operation. These include: O_2 at the economizer outlet; temperature in the upper furnace and at the economizer outlet; and steam and water flow rates, temperatures, and pressures.

Since no auxiliary fuel is used, the system is started up cold. First, the hopper doors are opened and the feed hopper is charged with refuse up to the normal operating level. Next, the grates are started and run intermittently until a refuse bed has been established. The induced-draft fan and the ESP's are also started at this time. The refuse is then lit manually, and the underfire and overfire air fans are started. The fuel-to-air ratio is controlled until stable conditions are reached, usually in two to three hours.

5.1.1.2 Emission Control Design and Operation. Each combustor is equipped with 2-field ESP. The ESP's have 97.5 percent design particulate control efficiencies. Table 5.1-1 summarizes pertinent ESP design and operating parameters. Each ESP operates with a gas flow of 180,000 acfm, and operating temperatures were reported to vary from 428 to 550°F depending on boiler conditions and cleanliness. There is a 31'-8" horizontal duct run from the economizer outlet to the ESP inlet. The State is requiring retrofit of acid gas controls by June 1, 1989. Wheelabrator anticipates demolishing the existing ESP's and installing spray dryers followed by fabric filters to achieve the State emission levels.

5.1.2 Description of Model Plant

5.1.2.1 Combustor Design and Operation. There are 7 operating plants in the existing population for large mass burn waterwall combustors. With the exception of Saugus, which began operating in 1975, the plants have all been built since 1982. Typical unit size is 750 tpd, except at Pinellas County, Florida where three 1000-tpd units are in place. Based on the distribution of unit sizes and numbers at the operating plants, the model for this subcategory is assumed to include three units with individual capacities of 750 tpd (total plant capacity 2,250 tpd).

Table 5.1-2 presents baseline data for the model plant. The physical configuration of the model plant is similar to the current design of the Saugus plant except that the model includes a ram feeder and several other design features which are more typical of the existing population. Each unit has three reciprocating grate section equipped with multiple, individual controlled underfire air plenums. Air preheat is available for use when firing wet refuse. Overfire air comprises 30 percent of total combustion air. It is assumed that overfire air firing patterns are established during initial start-up by in-furnace CO profiling. Each combustor operates at 100 percent excess air. Auxiliary fuel burners are available to provide 60 percent of the thermal load. The combustor arrangement is the same as shown in Figure 5.1-1 with the exception of the stepped grates, since the majority of the plants in this subcategory do not use stepped grates. A plot plant of the model plant is shown in Figure 5.1-2.

Each combustor is equipped with a boiler rated at 188,500 lb/hr of 675 psi, 875^{o}F steam. Normal operation is 95 percent of rated capacity (179,000 lb/hr). Soot removal cycles are hourly, achieved by mechanical rapping. Waste volume reduction is estimated to be 90 percent and weight reduction 70 percent.

TABLE 5.1-2. MODEL PLANT BASELINE DATA FOR LARGE MASS BURN WATERWALL COMBUSTOR

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 3
Combustor Unit Capacity	- 750
Emission Controls	
Type	- Electrostatic Precipitator
Number of Fields	- 3
Inlet Temperature	- 450°F
Collection Efficiency	- 99 percent
Gas Flow	- 187,500 acfm
Total Plate Area	- 73,800 ft^2
SCA at 187,500 cfm	- 394
Emissions:[a]	
CDD/CDF	- 500 ng/dscm
PM (stack)	- 0.02 gr/dscf[b]
CO	- 50 ppmv
HCl	- 500 ppmv
SO_2	- 200 ppmv
Stack Parameters:	
Height	- 230 feet
Diameter	- 9.5 feet
Operating Data:	
Remaining Plant Life	- ≥ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $16,500,00/year

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[a] All emissions are dry, corrected to 7 percent O_2.

[b] Inlet PM emissions to the ESP are 2.0 gr/dscf at 7 percent O_2.

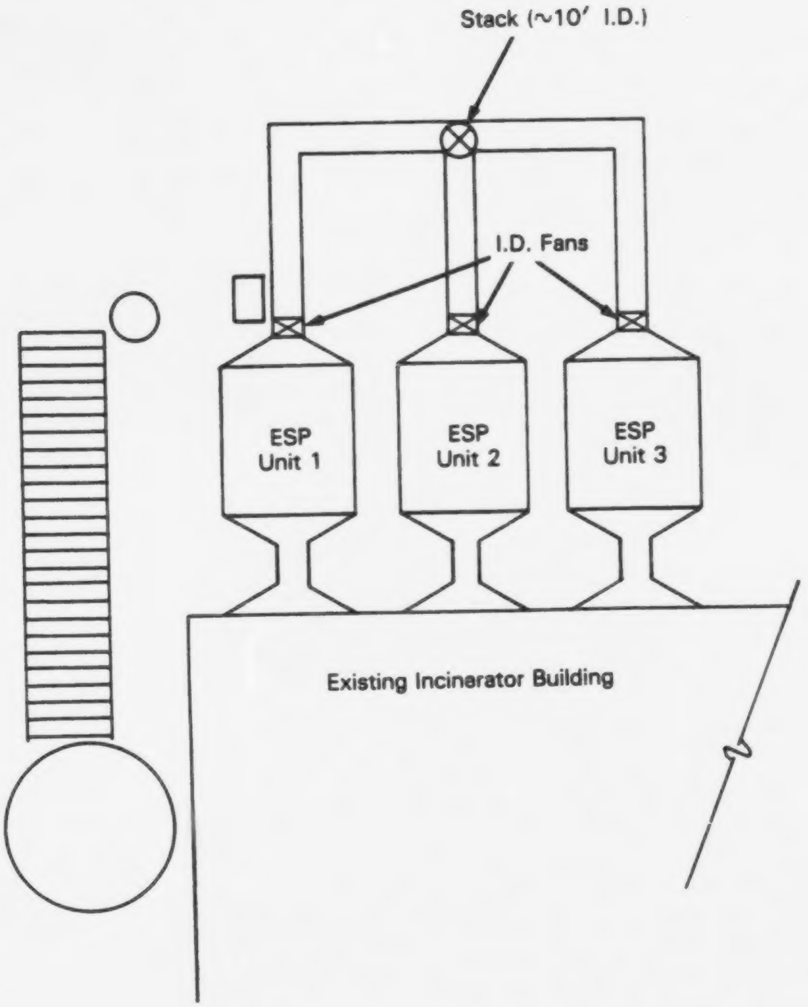

Figure 5.1-2. Plot plan of the model plant.

Combustion controls are largely automatic. The ram feeder frequency is modulated along with the underfire air to the middle region of the grate to maintain desired steam production levels. Grate speeds are adjusted manually. An oxygen monitor is located at the economizer exit. Temperatures are measured in the upper combustion chamber just prior to the convective section of the boiler, and at the economizer outlet. Based on an examination of the plants in this category, an economizer outlet temperature of 450°F is selected for the model plant.

At 100 percent excess air, total combustion air requirements are 90,300 scfm. Seventy percent of this figure (63,200 scfm) is supplied as underfire air and 30 percent (27,100 scfm) is overfire air. Assuming that all of the combustibles become flue gas products, and that there is no air inleakage to the combustor, the flue gas flow rate exiting the boiler is approximately 100,800 scfm (93,100 dscfm).

5.1.2.2 Emission Control System Design and Operation. As shown in Table 5.0-1, all 7 plants in the subcategory are equipped with ESP's. Although the Saugus plant has a 2-field ESP that achieves 97.5 percent PM removal and has emissions of less than 0.03 gr/dscf, the other five plants in this subcategory are equipped with ESP's that have at least three fields and achieve at least 99 percent PM removal. Available test data from three of these plants show PM emissions of less than 0.01 gr/dscf. Therefore, a 3-field ESP that achieves 99 percent PM removal is most representative of the existing population.

5.1.2.3 Environmental Baseline. Table 5.1-2 also presents the environmental baseline emission rates for the model plant. CDD/CDF stack emission data are available for 5 of the 7 facilities in the population. In addition, simultaneous uncontrolled and controlled CDD/CDF emissions were measured at four of these facilities. Based on these available data sets, average uncontrolled emissions of 500 ng/dscm CDD/CDF (tetra- through octa-) corrected to 7 percent O_2 are selected as a baseline emissions rate for the model.

Available data for the 6 of the 7 plants also supports an average CO emission value of 50 ppm and an average uncontrolled PM emission value of 2.0 gr/dscf, both corrected to 7 percent O_2.

Air emissions of HCl and SO_2 are largely dependent on waste feed content and do not vary appreciably due to combustion conditions. Changes in the chlorine and sulfur contents of the waste feed will directly affect HCl and SO_2 emissions. Based on the assumed waste composition used for this study, uncontrolled HCl and SO_2 emissions are estimated at 500 ppmv and 200 ppmv, respectively, both corrected at 7 percent O_2.

Assuming a waste volume reductions of 90 percent, weight reductions of 70 percent, and a nominal 750 tons of MSW per day, the total ash (dry) is estimated to be 225 tons/day. It is assumed that the bottom ash and fly ash are mixed and co-disposed, as is the practice at Saugus.

5.1.3 Good Combustion

The model plant has good combustion practices in place when considering design and operational features. Combustion controls are also judged to be state-of-the-art. The only additional requirement for the model plant is to install continuous CO monitors at the same location as the existing O_2 monitors to verify CO emission levels.

5.1.3.1 Costs. Table 5.1-3 presents capital and annual operating costs for installation of CO monitors. Capital costs of CO monitors for the model plants are estimated at \$86,000, including readouts and integrators. The annualized capital cost is \$11,000, based on a 10 percent interest rate and 15-year facility life. Total annualized costs are estimated to be \$169,000 per year.

5.1.4 Good Particulate Control

The existing ESP's are assumed to reduce PM loadings from 2.0 gr/dscf at the ESP inlet to 0.02 gr/dscf at the outlet, operating at 450^0F. Because the existing ESP's can reduce PM emissions below that required for good PM control (0.05 gr/dscf), no equipment modifications are required for this model plant to achieve good particulate control.

5.1.5 Best Particulate Control

5.1.5.1 Description of Modification. The existing ESP's have sufficient plate area to achieve best particulate control (0.01 gr/dscf PM emissions), but will require rebuilding to replace worn or damaged internal components (plates, frame, and electrodes), upgrading of controls and

TABLE 5.1-3. PLANT CAPITAL AND ANNUAL OPERATING COSTS FOR COMBUSTION MODIFICATIONS
(Three units of 750 tpd each)

Item		Costs ($1000)
CAPITAL COSTS:		
Direct Costs:		
CO monitors		66
	Total	66
Indirect Cost and Contingency		20
TOTAL CAPITAL COST		86
Downtime Cost		0
Annualized Capital Recovery		11
ANNUAL OPERATING COSTS:		
Direct Costs:		
Maintenance Labor		42
Maintenance Materials		42
	Total	84
Indirect Costs:		
Overhead		50
Taxes, Insurance, and Administration		3
Capital Recovery		11
	Total	64
TOTAL ANNUALIZED COST		148

electronics for more effective energization, and flow modeling to evaluate gas distribution. No additional plate area or changes in plate-electrode geometry are required. Downtime for this rebuild will be approximately 2 months for each unit.

5.1.5.2 Environmental Performance. Particulate matter emissions will be reduced from 0.02 to 0.01 gr/dscf. The additional recovered fly ash will add roughly 73 tons/yr to total solid waste disposal requirements. This is a 0.5 percent increase in fly ash to disposal. Emissions for CDD/CDF and acid gases are equal to the concentrations at the combustor exit.

5.1.5.3 Costs. Total capital cost requirements for best particulate control, presented in Table 5.1-4, are estimated at $1,990,000. This includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion factor for the ESP, and high APCD congestion factor for the ducting used for temperature control.

Annual costs are presented in Table 5.1-5 for best particulate control. The costs are dominated by annualized capital recovery and downtime. Indirect costs including capital recovery and downtime are estimated $959,000. Direct O&M costs are estimated at $2,000 per year. Total annualized costs are estimated at $961,000 per year.

5.1.6 Good Acid Gas Control

5.1.6.1 Description of Modification. To achieve good acid gas control, dry sorbent will be injected into the combustor through existing overfire air ports. Duct sorbent injection was not considered because of limited space between the economizer and the ESP. To reduce the inlet flue gas temperature to 350^{0}F, water will be sprayed into the ductwork between the economizer and the ESP for each combustor. Demolition of the existing ductwork between the economizer and the ESP is required for installing 32 feet of new ducting fabricated with water spray nozzles. The fabricated ducting has the same cross-sectional area of the existing ducting, because

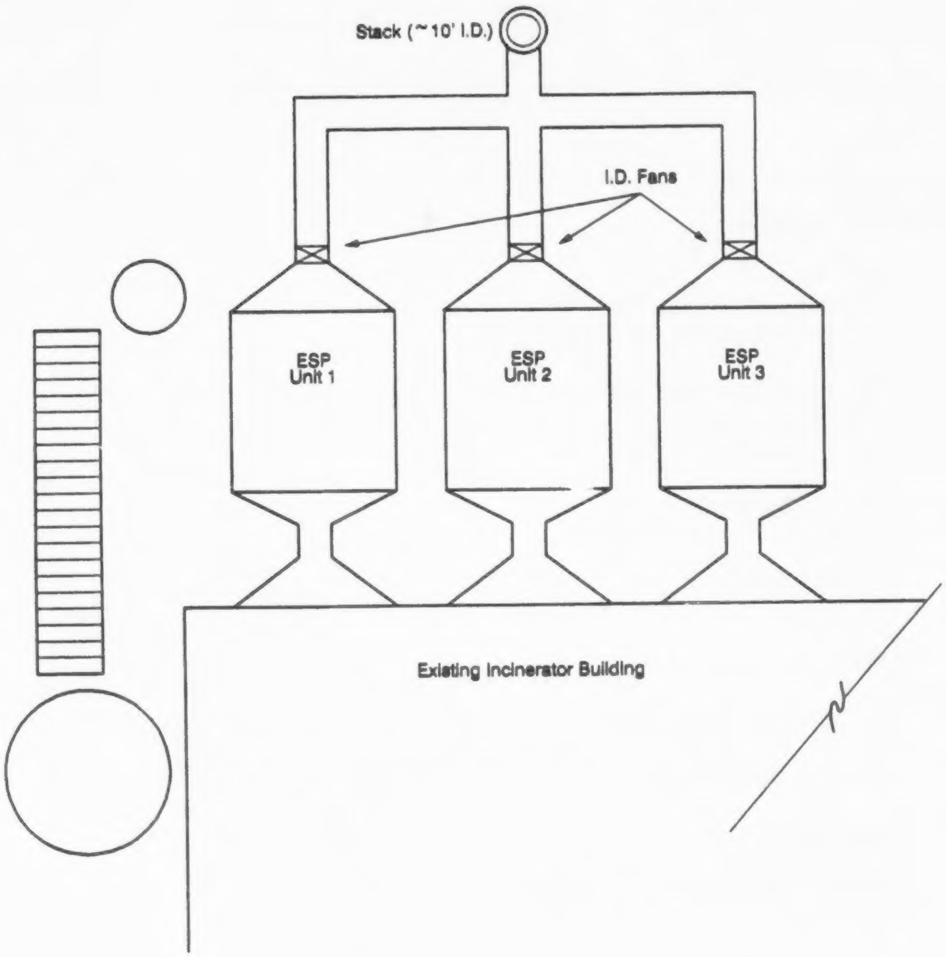

Figure 5.1-3. Plot Plan of Particulate Control Equipment

TABLE 5.1-4. PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROL
(Three units of 750 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
PM Control[a]	
Equipment (Rebuild ESP)	1,660
Access/Congestion Cost	NA[c]
New Flue Gas Ducting[a]	
Ducting Costs	NA
Access/Congestion Cost	NA
Other Equipment	
Fan	NA
Stack	NA
Demolition/Relocation	NA
Total	1,660
Indirect Costs and Contingencies	336
Monitoring Equipment[b]	0
TOTAL CAPITAL COST	1,990
DOWNTIME COSTS	5,300
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	959

[a] Based on moderate access/congestion.

[b] Turnkey.

[c] NA = not applicable.

TABLE 5.1-5 PLANT ANNUAL COST FOR PARTICULATE MATTER AND TEMPERATURE CONTROLS (Three units of 750 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	0
Electricity	0
Water	0
Waste Disposal	2
Monitors	0
Total	2
INDIRECT COSTS:	
Overhead	0
Taxes, Insurance, and Administration	0
Capital Recovery and Downtime	959
Total	959
TOTAL ANNUALIZED COST	961

enough residence time is already available for flue gas cooling (2.9 seconds) in the existing ductwork. A water rate of 39 gpm per combustor is required to cool the flue gas to 350°F.

New equipment for sorbent injection includes two storage silos, a pneumatic sorbent system, six sorbent feed bins (two for each combustor), and six pneumatic injection nozzles (two for each combustor). Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full-load, a sorbent injection rate of 878 lb/hr is required for each combustor.

In addition, the existing ESP will require a new ESP field to reduce PM emissions to 0.01 gr/dscf. This field is attached to each of the existing ESPs. The additional plate area for each ESP is 24,600 ft^2. New I.D. fans are also required to handle the additional pressure drop of the new field and ductwork. The project also includes monitoring equipment for HCl, SO_2, O_2, and opacity. Monitors for HCl, SO_2, O_2, and opacity will be located at the outlet of each ESP. Figure 5.1-4 shows the retrofit changes. Downtime is expected to be 2 months.

5.1.6.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 75 percent. Acid gas emission reductions are estimated at 50 percent for HCl and 50 percent for SO_2, respectively. As noted above, PM emissions would be reduced to 0.01 gr/dscf. An additional 13,600 tons/year of waste (sorbent and fly ash) will be added to the baseline waste disposal requirements for the plant.

5.1.6.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 5.1-6. Most of the cost is associated with temperature and particulate control equipment. Total capital cost is estimated at $7,740,000. This cost estimate assumes a moderate APCD access/congestion level and for sorbent injection and ESP upgrade, a high APCD access/congestion for the ducting used for temperature control, ductwork demolition of 60 feet per combustor, and new ID fans.

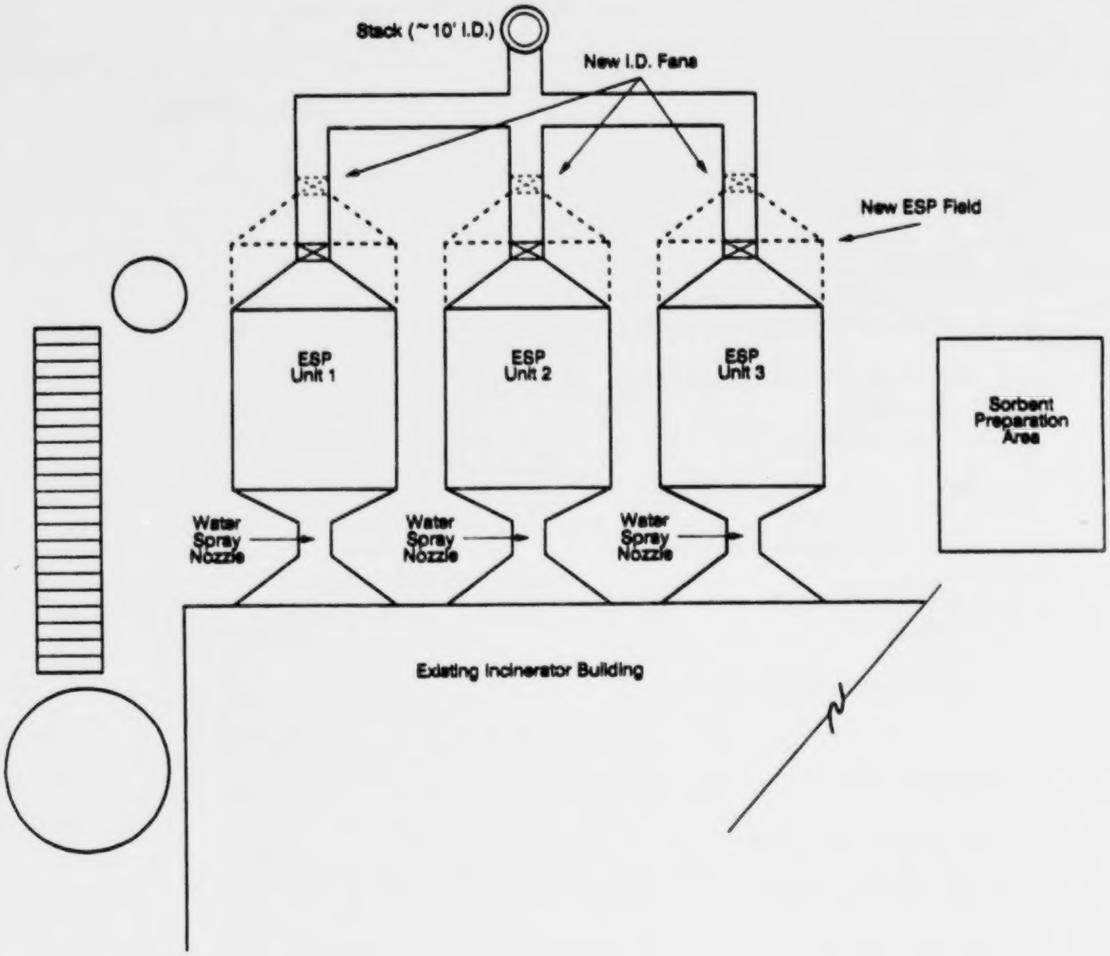

Figure 5.1-4. Plot Plan of Sorbent Injection Equipment Arrangement

TABLE 5.1-6. PLANT CAPITAL COST FOR DRY SORBENT INJECTION
WITH ADDITION OF ESP PLATE AREA
(Three units of 750 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Acid Gas Control[a]	
Equipment	896
Access/Congestion Cost	90
Particulate and Temperature Control[a,b]	
Equipment	3,530
Access/Congestion Cost	687
New Flue Gas Ducting[a]	
Ducting Cost	304
Access/Congestion Cost	88
Other Equipment	
Fan	931
Stacks	0
Demolition/Relocation	50
Total	6,570
Indirect Cost & Contingencies	2,760
Monitoring Equipment[c]	859
TOTAL CAPITAL COST	10,200
DOWNTIME COSTS	5,300
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	2,040

[a] Based on moderate access/congestion.

[b] Based on high access/congestion for ducting of temperature control.

[c] Turnkey.

Annual O&M and indirect costs are presented in Table 5.1-7. Major direct operating costs are associated with lime, solid waste disposal, and monitor maintenance. The largest annualized cost is capital recovery and downtime. The total annualized cost for the control option is $3,650,000 per year.

5.1.7 Best Acid Gas Control

5.1.7.1 Description of Modifications. To achieve greater reductions of CDD/CDF, SO_2, and HCl, a new spray dryer/fabric filter system will be installed on each combustor. The existing ESP will be demolished to make room for the spray dryer vessels. Lime slurry will be introduced in each spray dryer at a 2.5:1 calcium-to-acid gas molar ratio. Water in the lime slurry of 30 gpm will be required to cool the flue gas to $300^{o}F$ for each combustor. The proposed equipment layout is illustrated in Figure 5.1-5.

This sketch also shows the location of the lime receiving, storage, and slurry area which will serve the spray dryers. A fabric filter with 41,000 effective square feet of cloth (net air-to-cloth ratio of 4:1) will be installed following each spray dryer. The increased pressure drop of a fabric filter over an ESP will require a new ID fan for each unit as well. An estimated 80 feet of new duct will be needed to connect the spray dryer/fabric filter to the existing stack. New monitoring instruments for HCl, SO_2, and O_2 will be installed at both the inlet to the spray dryer and the outlet of the fabric filter. An opacity monitor will be installed at the outlet of the fabric filter. Downtime is expected to be 2 months for ductwork tie-in and ESP demolition.

5.1.7.2 Environmental Performance. Total CDD/CDF emission reductions of 99 percent to 5 ng/dscm will result. Emissions of PM will be reduced from 0.02 gr/dscf to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl.

5.1.7.3 Costs. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 5.1-8. Total capital cost is estimated at $34,000,000. This figure includes purchase equipment, installation, ESP demolition, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion, 80 feet of new ductwork, and new ID fans.

TABLE 5.1-7. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA
(Three units of 750 tpd each)

Item		Costs ($1000)
DIRECT COSTS:		
Operating Labor		90
Supervision		35
Maintenance Labor		40
Maintenance Materials		122
Electricity		81
Water		14
Lime		843
Waste Disposal		342
Monitors		322
	Total	1,890
INDIRECT COSTS:		
Overhead		167
Taxes, Insurance, and Administration		374
Capital Recovery and Downtime		2,040
	Total	2,580
TOTAL ANNUALIZED COST		4,470

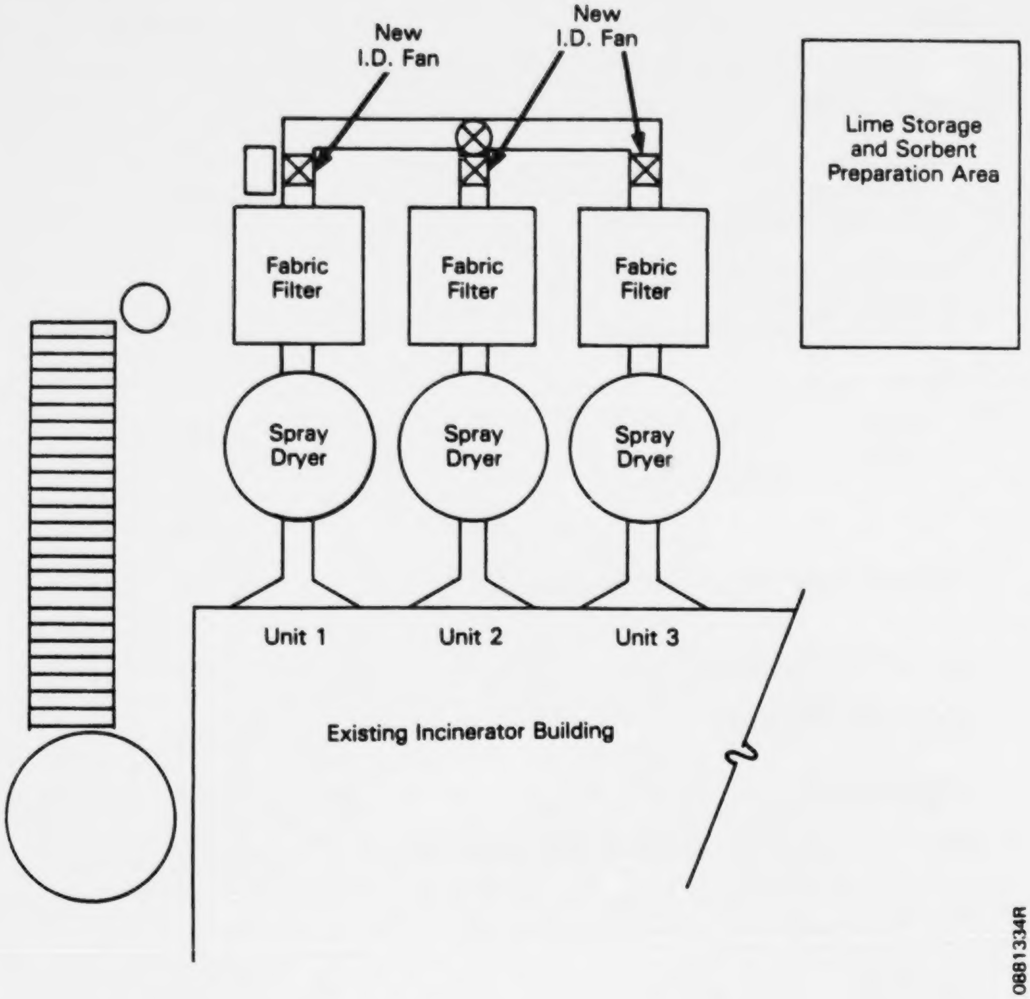

Figure 5.1-5. Plot plan of spray dryer/fabric filter retrofit equipment arrangment.

TABLE 5.1-8 PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Three units of 750 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Acid Gas Control[a]	
Equipment	14,400
Access/Congestion Cost	3,610
New Flue Gas Ducting[a]	
Ducting Cost	161
Access/Congestion Cost	40
Other Equipment	
Fans	1,000
Stacks	0
Demolition/relocation	2,390
Total	21,600
Indirect Cost and Contingencies	11,500
Monitoring Equipment[b]	859
TOTAL CAPITAL COST	34,000
DOWNTIME COST	5,300
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	5,160

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[a] Based on moderate access/congestion.

[b] Turnkey.

Annual operating costs are presented in Table 5.1-9. Significant direct operating expenses include maintenance materials, electricity for the larger ID fan needed due to increased pressure drop access in the fabric filter, and monitoring equipment maintenance. Total annualized costs, including capital recovery and downtime, would be $9,410,000.

5.1.8 Summary of Control Options

5.1.8.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 5.1-10 summarizes the combustion, particulate control, and acid gas control technologies described in Sections 5.1.3 through 5.1.7 that were combined for each of the control options described in Section 3.0. Of the seven options, Options 1 and 2 would be the same for this plant, because good combustion practices are in place and baseline PM emissions are below good PM control level of 0.05 gr/dscf.

5.1.8.2 Environmental Performance. The performance of each control option is summarized in Table 5.1-11. For each pollutant, the table presents both the pollutant concentrations and annual emissions. The greatest reductions on acid gases, particulate matter, and CDD/CDF all are achieved with a spray dryer/fabric filter system. Then next most effective control for all these pollutants is the dry sorbent injection technology. Dry sorbent injection technology increases the baseline. Solid waste disposal by about 6 percent, and the spray dryer/fabric filter system increases the baseline solid waste disposal by about 5 percent.

5.1.8.3 Costs. The total annualized cost of each option is presented in Table 5.1-12. The most expensive control option is the spray dryer/fabric filter installation with combustion modification (Option 7). The total capital cost for this option is $34,100,000 and the total annualized cost is $9,550,000. This annualized cost is roughly 65 times higher than the annualized costs for Option 1. Overall, both capital and annualized costs are higher for higher levels of control.

5.1.8.4 Energy Impacts. Table 5.1-13 presents a summary of the energy impacts associated with the control options. The energy use figures are incremental use. The spray dryer with fabric filter control options

TABLE 5.1-9. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 750 each)

Item		Costs ($1000)
DIRECT COSTS:		
Operating Labor		144
Supervision		22
Maintenance Labor		79
Maintenance Materials		545[a]
Compressed Air		91
Electricity		626
Water		22
Lime		696
Waste Disposal		443
Monitors		322
	Total	2,990
INDIRECT COSTS:		
Overhead		378
Taxes, Insurance, and Administration		1,230
Capital Recovery and Downtime		5,160
	Total	6,770
TOTAL ANNUALIZED COST		9,760

[a] Includes bag replacement costs of $160,000.

TABLE 5.1-10. SUMMARY OF CONTROL OPTIONS FOR LARGE MASS BURN WATERWALL COMBUSTOR

			Particulate Control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion Control	X	X					
3. Best PM Control and Combustion and Temperature Control	X	X		X			
4. Good Acid Gas Control, Best PM Control and Temperature Control	X	X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control	X	X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X			X		X

TABLE 5.1-11. ENVIRONMENTAL PERFORMANCE SUMMARY FOR LARGE MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three Units of 750 TPD Each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	500	500	500	500	125	125	5	5
Mg/yr[b]	1.5E-3	1.5E-3	1.5E-3	1.5E-3	3.6E-4	3.6E-4	1.5E-5	1.5E-5
% Reduction vs. Baseline	--	0	0	0	75	75	99	99
CO Emissions								
(ppmv)	50	50	50	50	50	50	50	50
Mg/yr	169	169	169	169	169	169	169	169
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01
Mg/yr	133	133	133	67	67	67	67	67
% Reduction vs. Baseline	--	0	0	50	50	50	50	50
SO_2 Emissions								
(ppmv)	200	200	200	200	100	100	19	19
Mg/yr	1,630	1,630	1,630	1,630	815	815	155	155
% Reduction vs. Baseline	--	0	0	0	50	50	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	250	250	15	15
Mg/yr	2,380	2,380	2,380	2,380	1,190	1190	71	71
% Reduction vs. Baseline	--	0	0	0	50	50	97	97
Total Solid Waste								
(tons/day)	675	675	675	675	716	716	727	727
Mg/yr	204,000	204,000	204,000	204,100	216,400	216,400	220,300	220,300
% Increase vs. Baseline	--	0	0	0.03	6	6	8	8

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[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis.

[b] Mass emission rates are for total plant (both combustors).

TABLE 5.1-12. COST SUMMARY FOR LARGE MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(3 units at 750 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	86	86	2,800	10,200	10,290	34,000	34,100
Downtime Cost	0	0	5,300	5,300	5,300	5,300	5,300
Annualized Capital and Downtime Cost	11	11	970	2,040	2,050	5,160	5,170
Direct O&M Cost	84	84	86	1,890	1,970	2,990	3,070
Total Annual Cost	143	143	1,100	4,470	4,610	9,760	9,900
Cost Effectiveness ($/ton MSW)	0.20	0.20	1.47	5.96	6.15	13.10	13.20
Facility Downtime (Months)	0	0	2	2	2	2	2
Total Compliance Time (Months)	13	13	13	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

TABLE 5.1-13 ENERGY IMPACTS FOR LARGE MASS BURN WATERWALL COMBUSTOR CONTROL OPTIONS

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1.	0	0
2.	0	0
3.	195	0
4.	1,500	0
5.	1,500	0
6.	13,600[b]	0
7.	13,600[b]	0

[a] Increase from baseline consumption.

[b] Total electrical use excludes the electrical savings of not operating the existing ESP's.

consume the most electricity, about 10,500 MW/yr. Auxiliary fuel is fired for these options and baseline requiring combustion modifications all at the same rate of 36 billion Btu per year. Therefore, no increase in auxiliary fuel consumption from baseline is expected for the seven options.

5.2 MID-SIZE MASS BURN WATERWALL COMBUSTOR

This section presents the case study for a model mid-size mass burn waterwall municipal waste combustor (MWC). This subcategory comprises mass burn waterwall combustors with individual combustor capacities between 275 and 600 tpd. As shown in Table 5.0-1, there are eight known plants in this subcategory. Five of these eight plants have started operating in the last two years. The remaining four plants were built between 1970 and 1974. A facility expansion also occurred at the Nashville plant in 1986. Six of the eight existing facilities are equipped with electrostatic precipitators (ESP's); two plants were built with spray dryer/fabric filter systems.

Section 5.2.1 presents a description of the Nashville Thermal Plant, which was visited in order to gather information for model development. Section 5.2.2 presents a description of the model plant. Sections 5.2.3 through 5.2.6 detail the retrofit modifications, estimated performance, and costs associated with various control options. Section 5.2.7 summarizes the control options, which are discussed in more detail in Section 3.0 of this report.

5.2.1 Description of Nashville Thermal Plant[3]

The Nashville Thermal Plant began operating in 1974. At that time, the plant consisted of one gas/oil standby boiler (#1) and two waste-fired combustors (#2 and #3). Each of the original waste-fired units has a rated capacity of 360 tpd of MSW. An additional waste-fired combustor (#4) started up in 1986. The #4 combustor has a rated capacity of 400 tpd. All three of the waste-fired boilers are equipped with Detroit Stoker grates and Babcock and Wilcox (B&W) boilers, and each is equipped with a 4-field ESP. The three units operate continuously, 7-days/week.

Table 5.2-1 presents design and operating data for the plant. The plant is unique in that it was the first waste-fired plant in the U.S. to provide district heating and cooling. Steam and chilled water are supplied to more than thirty buildings in downtown Nashville, some of which rely solely on the waste-fired plant for heating and cooling. Two steam-driven centrifugal chillers were originally in place with the #2 and #3 units. With the plant expansion, two additional chillers brought total chilled water capacity to 27,000 ton/hr. The expansion also included installation of a 7.3 MW turbine-generator. Electricity is sold to the Tennessee Valley Authority.

TABLE 5.2-1. NASHVILLE THERMAL DESIGN AND OPERATING DATA

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 3
Individual Combustor Capacity	- 360 tpd (#2 and #3) - 400 tpd (#4)
Steam Production:	
Design Steam Capacity	- 80,000 lb/hr (#2 and #3) - 90,000 lb/hr (#4)
Maximum Steam Capacity	- 100,000 lb/hr (#2 and #3) - 120,000 lb/hr (#4)
Steam Conditions	- 400 psig at 600°F
Emissions Control:	
Type	- Electrostatic Precipitator
Manufacturer	- American Air Filter
Number of ESP's	- 3 (one per combustor)
Number of Fields	- 4 each
Design PM Operating Temperatures	- 450 to 650°F
Actual PM Operating Temperature	- 400 to 500°F
Inlet Particulate Loading (typical)	- 1.5 gr/dscf
Design Collection Efficiency	- 99%
Measured Collection Efficiency	- 98.8%
Particulate Emission Limit	- 0.025 gr/dscf
Design Gas Flow	- 140,000 acfm at 650°F (115,000 acfm at 450°F)
Total Plate Area	- 44,240 square feet
SCA at 115,000 acfm, 450°F	- 385
Design Superficial Gas Velocity	- 3.5 ft/sec
Residence Time	- 14 seconds
Dimensions (length x width x height)	- 40 x 25 x 33 feet
Tested Emissions (Unit #4)	
Particulate Matter	- 0.018 gr/dscf
SO_2	- 105 ppm
NO_x	- 96 ppm
CO	- 2.5 ppm[a]

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[a] Plant personnel feel that CO emissions from the older units (#2 and #3) would probably be higher than this value.

An underground distribution network contains steam supply and condensate return headers, and chilled water supply and return lines. Nearly all of the condensate and chilled water is returned to the plant so that make-up water is minimized.

5.2.1.1 Combustor Design and Operation. Waste is delivered to the plant six days/week, and consists largely of residential solid waste. Three cranes are available, with two normally on standby. Waste is transferred from the pit to the individual combustor hoppers where it is charged to the combustor by hydraulic rams. The ram feeders were retrofit on units #2 and #3 in 1978 and ram speeds are varied manually. On the #4 unit, the ram cycle is automatically adjusted as part of the combustion control system.

Each of the combustors contains three grate sections: (1) drying, (2) burning, and (3) finishing. The grates are reciprocating type, with alternating stationary and moving portions. The newer Detroit Stoker grates on unit #4 are steeper (12^0 angle) than those in the #2 and #3 units (6^0 angle), and the design of the grate bars also varies. Grate wear was a common problem which has been corrected by the installation of a new chrome/nickel alloy.

Each grate section contains two independently controlled underfire air plenums. On the older units (#2 and #3), adjustments to underfire air damper settings are made manually, and in the #4 unit the settings are adjusted automatically to maintain an established underfire air distribution. In all units the majority of the underfire air is provided to the middle (burning) grate. Steam coil air preheaters are in place to supply 150^0F combustion air to all three plenums when firing wet refuse.

Each combustor is designed to operate at 80 percent excess air, and the original overfire/underfire air ratio was 15/85. Separate forced-draft fans supply overfire and underfire air to each combustor. Excessive tube wastage problems in early years of operation were an indication that the ratio of overfire to underfire air was insufficient. Due to capacity limitations in the original overfire air fans, new fans and overfire air ports were installed in 1982 to adjust the ratio to 40/60 at 80 percent excess air.

The original overfire air system consisted of two rows of nozzles across the front wall and a single row of nozzles across the rear wall. All of these nozzles were 1-1/4 inches in diameter, and each row included

14 nozzles. The overfire air fan provided a maximum pressure of 18 inches of H_2O gage in the supply header. In 1975 an additional row of 14 nozzles was added to the lower front wall.

The new overfire air system consists of the four rows of nozzles described above and 16 nozzles on each side wall, supply headers, and a new fan and motor. The side wall nozzles are squashed pipe approximately 1-1/16 inches wide by 3-1/2 inches high and fit between the existing waterwall tubes in the membrane wall.

The maximum horizontal distance from front to rear combustor walls is 15 feet 5 inches at the elevation of the lower overfire air nozzles. This distance is reduced in the upper combustor by a bull nose that extends two feet horizontally from the front wall. Plant personnel indicated that normal pressure settings on the front and rear wall overfire air supply headers is 30 inches of water gage, and 15 inches of water gage on the side walls. Two combination gas/oil burners are located on the combustor rear wall 5 to 6 feet above the highest overfire air jets. Profiles of the original and new combustors are shown in Figures 5.2-1 through 5.2-3.

Gas temperatures are recorded in the upper combustors and at several downstream locations in the system. The combustor exit gas temperature is reported to be 1400 to 1500^{0}F. The economizer inlet gas temperature is approximately 760^{0}F, and the flue gases at the economizer exit are approximately 460^{0}F.

Gas is fired during process start-up and the combustor temperatures are stabilized on refuse after approximately three hours. There is no requirement to attain a specific combustion temperature prior to charging waste feed. Total gas burner capacities were reported to be 50 percent of total thermal load.

Units #2 and #3 are equipped with pneumatic controls which maintain a constant steam flow by varying underfire air flows. Ram feeder and grate speeds are adjusted manually. Unit #4 is equipped with a Bailey Network 90 Combustion Control system which provides total system control. Underfire air is controlled automatically with a variable speed forced-draft fan, providing constant steam pressure at a targeted steam flow. There are automatic dampers on the overfire air fans. Grate and ram speeds are

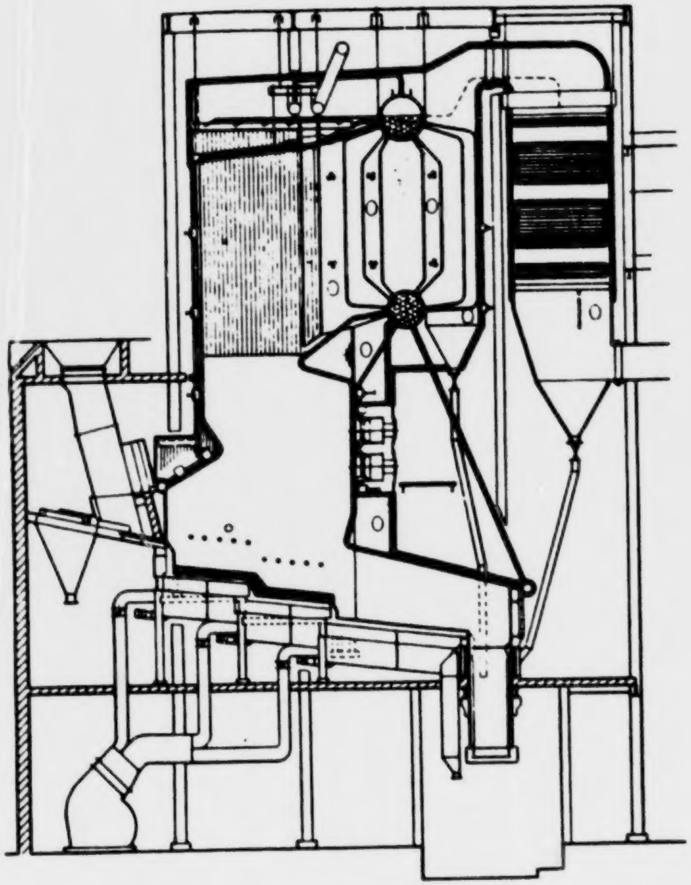


Figure 5.2-1. Configuration of Original Combustor (#2).

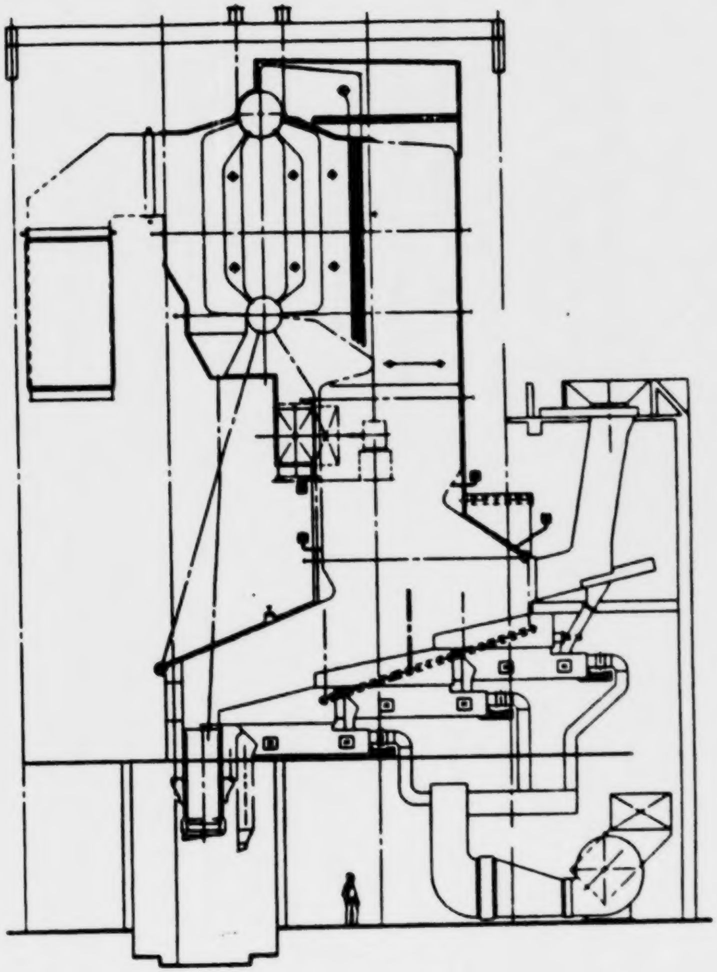


Figure 5.2-2. Configuration of New Combustor (#4).

(Figures provided by Nashville Thermal Transfer Corp.)

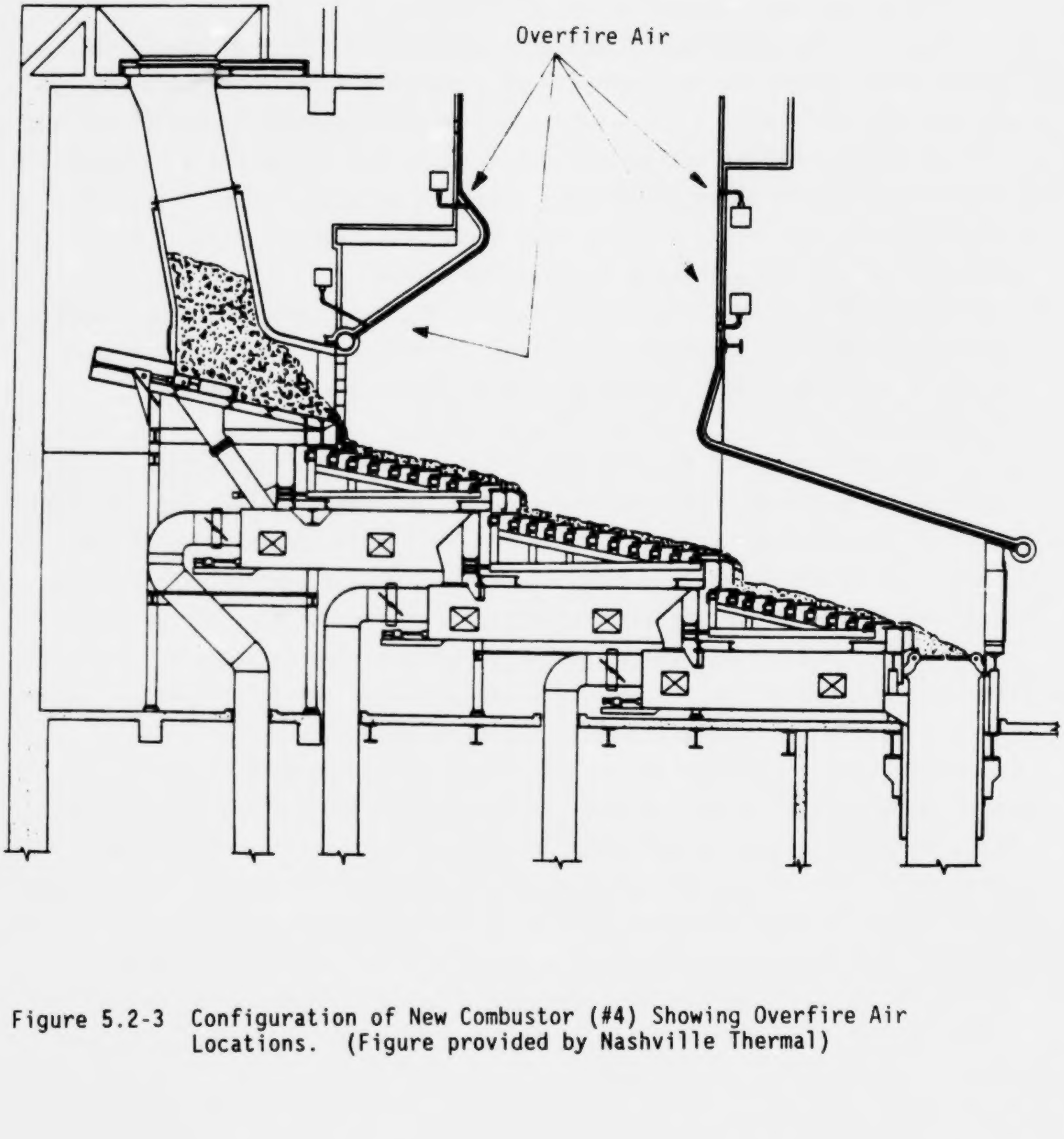


Figure 5.2-3 Configuration of New Combustor (#4) Showing Overfire Air Locations. (Figure provided by Nashville Thermal)

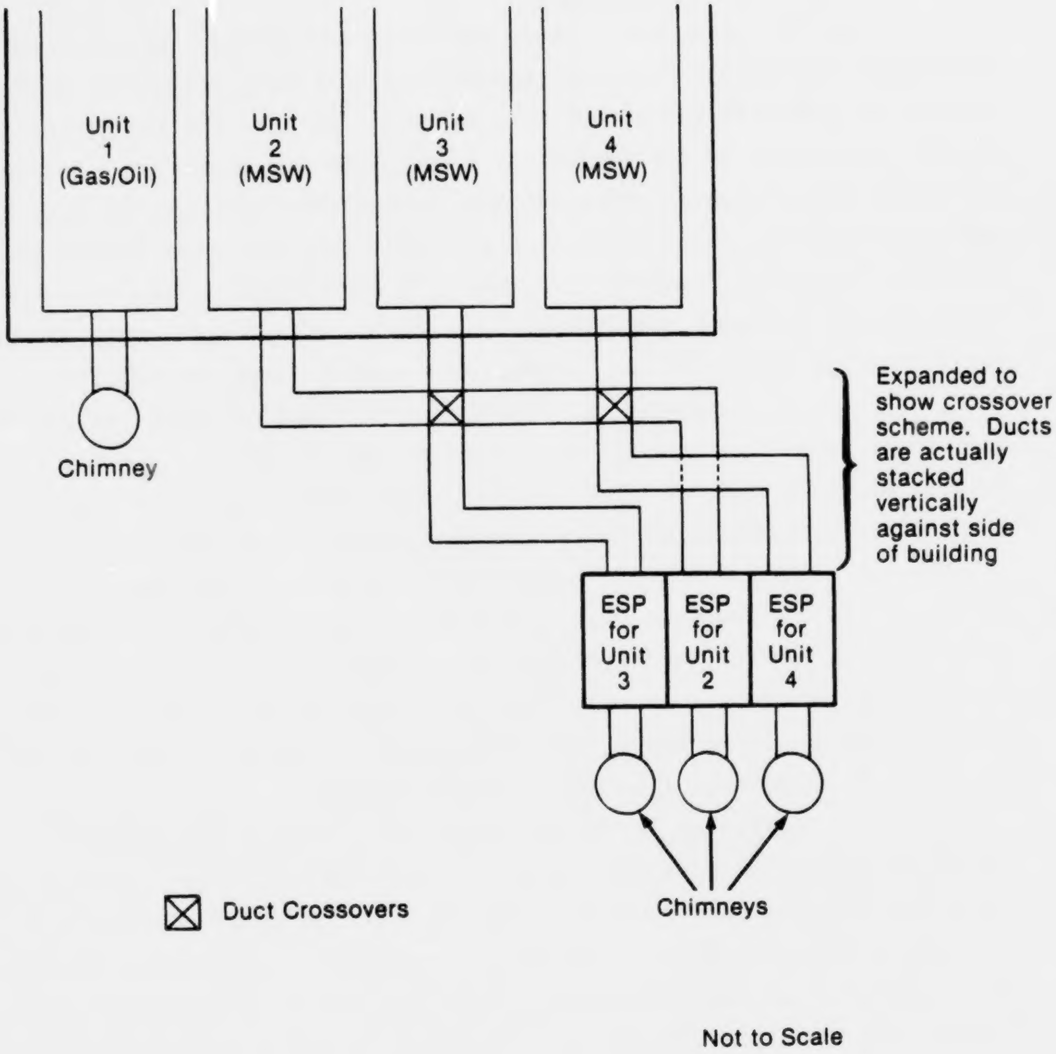
controlled automatically, but can be manually overridden. The control system has O_2/CO trim for excess air control (tied to underfire air system), and there is capacity for future installation of combustor temperature override to increase underfire air flows with falling combustor temperatures, thus overriding the normal underfire air flow control.

5.2.1.2 Emission Control Design and Operation. Each of the three waste-fired combustors is controlled by a separate 4-field ESP manufactured by American Air Filter. ESP's were added to the original combustors (#2 and #3) in 1976 to replace wet scrubbing systems. Each of the ESP's at Nashville Thermal achieve PM emissions of less than 0.02 gr/dscf. Despite the age difference of the units, the ESP's are virtually identical. Table 5.2-1 presents design and operating data for the #4 ESP.

Figure 5.2-4 shows the unusual duct arrangement from the boiler outlets to the ESP inlets. Crossovers are provided between #2 and the other two units to allow continued operation of a boiler in the event an ESP is inoperative.

The ESP's have not been rebuilt since they were put in service. Despite the operating temperatures, which are often lower than design, the operators have not experienced corrosion problems. One reason for this may be the continuous boiler operation, which keeps the flue gas temperature above the acid dew point, preventing acid condensation on the surfaces of the ESP.

Spatial constraints at the back end of the system are severe. There is probably not enough space at the back end of the system for a complete spray dryer/fabric filter retrofit due to the close proximity of the existing chimneys, ESP's, cooling towers, and transformers. However, there is substantial space toward the front of the plant. The parking area beside Unit #4 would have to be relocated to make space available for a spray dryer/fabric filter system. Also, space is available, with some limitations, beside Unit #1 along the Cumberland River. The addition of a planned Unit #5 will further constrain this area and make the retrofit of acid gas controls difficult. Unit #2 has existing ductwork of about 100 feet prior to the ESP. Units #3 and #4 have significantly shorter duct runs. As such, sufficient



Expanded to show crossover scheme. Ducts are actually stacked vertically against side of building

Not to Scale

Figure 5.2-4. Duct Configuration at Nashville Thermal.

duct residence time may be available for a duct sorbent injection system, but the unusual duct arrangement discussed above would preclude installation of such a system without major duct reconfigurations.

5.2.2 Description of Model Plant

As shown in Table 5.0-1, there are eight operating plants in this subcategory of MWC's. The eight operating plants have individual units ranging in size from 275 to 400 tons per day. Despite the age of the older plants, nearly all of the facilities incorporate the majority of design and operating elements which represent good combustion practices for mass burn waterwall systems. This group of plants typically use a ram feeder and have multiple, separately controllable underfire air plenums. They also typically have properly designed overfire air systems to provide full coverage and penetration of the combustor. Combustion control loops are established to maintain constant steam flow by automatic adjustment of underfire air flows. Excess air levels are maintained between 80 and 100 percent. A few of the systems may have more advanced controls, including oxygen trim loops, temperature control loops, and automatic adjustments to ram speeds. The majority of plants also contain auxiliary fuel burners for start-up, shutdown, and equipment preheat. Typically, these plants are equipped with a continuous O_2 monitor, and airflow, temperature, steam, and feedwater controls and monitors. In addition, typical economizer flue gas exit temperatures are below 450°F, thus minimizing the potential for CDD/CDF formation in downstream flue gas treatment equipment.

5.2.2.1 Combustor Design and Operation. Table 5.2-2 presents operating and design data for the model plant. A model plant consisting of three 360-tpd mass burn waterwall combustors was selected based on the population described above. The units are assumed to operate at 80 percent excess air with an overfire/underfire air ratio of 30/70. Both of these figures are typical values for the facilities in the existing population. Each combustor has two gas burners which are used during start-up and shutdown. The burners are located on the rear wall just above the overfire air ports. Underfire air flow rates are adjusted automatically to maintain constant steam flows. Grate speeds are adjusted manually. Temperatures are monitored in the upper combustor and at the economizer outlet. Oxygen is continuously monitored at the economizer outlet.

TABLE 5.2-2. MODEL PLANT DESIGN AND OPERATING DATA FOR MID-SIZE MASS BURN WATERWALL COMBUSTOR

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 3
Individual Combustor Capacity	- 360 tpd (each)
Steam Production:	
Design Steam Capacity	- 80,000 lb/hr, each boiler
Steam Conditions	- 400 psig at 600°F
Emissions Control:	
Type	- Electrostatic Precipitator
Number of ESP's	- 3 (one per combustor)
Number of Fields	- 4
Operating Temperature	- 450°F
Inlet Particulate Loading (typical)	- 2.0 gr/dscf
Design Collection Efficiency	- >99%
Gas Flow	- 82,000 acfm at 450°F
Total Plate Area	- 34,700 square feet
SCA at 82,000 acfm and 450°F	- 425
Emissions:[a]	
CDD/CDD (octa - tetra)	- 200 ng/dscm
PM	- 0.01 gr/dscf
CO	- 50 ppmv
HCl	- 500 ppmv
SO$_2$	- 200 ppmv
Stack Parameters:	
Height	- 200 ft
Diameter	- 7 ft
Operating Data:	
Remaining Plant Life	- $\geq$ 20 years
Operating Hours per Year	- 8000
Annual Operating Cost	- $10,600,00/year

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[a] All emissions are dry, corrected to 7 percent O$_2$. Standard and normal conditions are 1 atmosphere and 70°F.

At a flue gas flow rate of 80 percent excess air, total combustion air are approximately 39,000 scfm. Underfire air flow is 27,300 scfm and overfire air flow is 11,700 dscfm. Total flue gas air flow at the boiler exit, including flue gas products, is approximately 48,000 scfm (41,400 dscfm).

5.2.2.2 Description of Emission Controls. As shown in Table 5.0-1, the majority of plants in this subcategory are equipped with ESP's. These ESP's are typically operated at temperatures lower than 450°F and achieve at least 99 percent removal of PM. Acid gas controls are not typically in place at these plants.

The model plant for this subcategory is equipped with dedicated 4-field ESP's similar to those in place at Nashville. Operating data for the ESP's are given in Table 5.2-2. It is assumed that the model plant ESP's operate at a temperature of 450°F, are well-operated, and have sufficient SCA at 450°F to achieve an outlet PM loading of 0.01 gr/dscf.

The existing duct arrangement is not assumed to be typical of the existing population of mid-size mass burn waterwall plants. The site congestion at Nashville is also not typical, since Nashville Thermal was intentionally located in the downtown area to provide district heating and cooling. As previously discussed, this aspect is unique for plants in this subcategory. For purposes of representative model development, the model plant is assumed to have a standard duct arrangement and moderate APCD congestion, as shown in Figure 5.2-5. It is also assumed that each ESP is equipped with its own stack. Stack parameters for the model plant are also presented in Table 5.2-2.

5.2.2.3 Environmental Baseline. Table 5.2-2 also presents the environmental baseline for the model plant. Five of the plants in this subcategory have reported emissions of CDD/CDF. From this available data, it is assumed that the model plant has baseline emissions at the combustor exit of 200 ng/dscm CDD/CDF corrected to 7 percent O_2. ESP's operating at 450°F are assumed to neither promote nor deter formation of CDD/CDF. Therefore, CDD/CDF emissions at the stack are assumed to be equal to CDD/CDF emissions at the combustor exit.

Based on measured data from plants in this subcategory, an uncontrolled PM emission rate of 2.0 gr/dscf at 7 percent O_2 was selected for the model plant. The ESP's are assumed to reduce this level to 0.01 gr/dscf at the

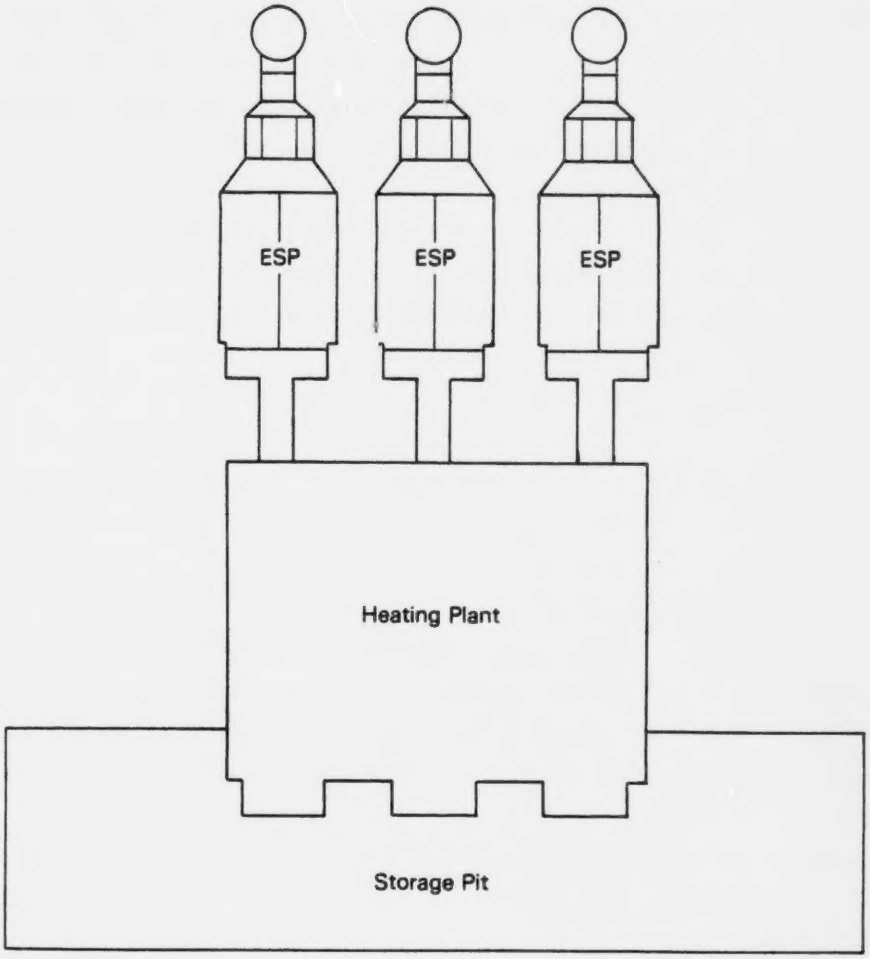

Figure 5.2-5. Plot Plan of Model Plant

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stack. Baseline CO emissions are assumed to be 50 ppmv at 7 percent O_2, also based on data from other plants in the population. Based on the waste composition used in this study, baseline emissions of HCl and SO_2 are assumed to be 50 ppmv and 200 ppmv respectively. It is assumed that the combustion process reduces waste 90 percent by volume and 70 percent by weight.

5.2.3 Good Combustion

An analysis of the model plant design and operation indicates that good combustion practices are largely in place. The only additional requirement for the model plant is the installation of continuous CO monitors for performance verification. Each unit should be equipped with a CO monitor with readout and integrator. Installation of this equipment can be performed during a routine scheduled outage, so that the modification will not cause any unscheduled downtime.

5.2.3.1 Costs. Plant costs for combustion modifications are shown in Table 5.2-3. It is estimated that the capital cost of installing CO monitors will be $86,000, and that the annualized costs, including annualized capital, will be $148,000 yearly.

5.2.4 Best Particulate Control

The existing ESP's are assumed to reduce PM loadings from 2.0 gr/dscf at the ESP inlet to 0.01 gr/dscf at the outlet. Thus no equipment modifications are required for this model plant to achieve 0.01 gr/dscf, the emission level associated with best particulate control.

5.2.5 Good Acid Gas Control

5.2.5.1 Description of Modifications. For good acid gas control on each combustor, dry calcium sorbent will be injected into the duct upstream of the ESP. Water will also be sprayed into the duct at this point, to cool the gas stream to $350^{o}F$. This cooling is estimated to require 8 gpm of water per combustor.

Required equipment to accomplish the sorbent injection includes a sorbent storage silo, a pneumatic sorbent conveying system, three sorbent feed bins, and pneumatic injection nozzles for each combustor. Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full load, this requires a sorbent injection rate of 407 lb/hr per combustor.

TABLE 5.2-3 PLANT COSTS FOR COMBUSTION MODIFICATIONS
(Three units of 360 tpd each)

Item	Cost ($1000)
CAPITAL COSTS:	
CO monitors, with readouts and integrators	66
Indirect costs	20
TOTAL CAPITAL COSTS	86
Downtime Costs	0
ANNUALIZED CAPITAL COST AND DOWNTIME	11
ANNUAL OPERATING COSTS:	
Direct Costs:	
Maintenance and Labor	42
Maintenance and Materials	42
Total	84
Indirect Costs:	
Overhead	50
Taxes, Insurance, Administration	3
Capital Recovery	11
Total	64
TOTAL ANNUALIZED COST	148

To control the additional particulate loading generated by the lime sorbent, plate area will be added to maintain PM emissions at 0.01 gr/dscf. An additional 5,300 square feet of ESP collection area will be added to each ESP using a separate ESP in series behind each existing unit. The project also includes monitoring equipment for HCl, SO_2, and CO_2, and new ID fans. Figure 5.2-6 shows these retrofit changes.

There are no access and congestion problems related to the addition of water lines and pumps for humidification. However, replacement of each economizer exit duct with a new duct containing sorbent and water injection nozzles is highly restricted since the duct passes through the heating building wall to the outdoor ESP. Access/congestion level for the lime sorbent conveying equipment and the additional ESP's is assumed to be moderate. An additional 150 feet of new ducting will be required to connect each new ESP to an existing stack. Combustor downtime can be limited to approximately 1 month for each unit.

5.2.5.2 Environmental Performance. CDD/CDF emissions are expected to be reduced by 75 percent from baseline levels. Acid gas emission reductions are estimated at 80 percent for HCl and 40 percent for SO_2, respectively. As mentioned above, PM emissions will be maintained at 0.01 gr/dscf. An additional 6,290 tons/per year of solid sorbent waste will be added to the site disposal requirements. This represents a 6 percent increase in solid waste.

5.2.5.3 Costs. Capital costs for duct sorbent injection are presented in Table 5.2-4. Total capital cost is estimated at $6,800,000. Most of this cost is associated with upgrading particulate control equipment. Downtime cost is also substantial, at $1,270,000. Annual operating and maintenance costs are presented in Table 5.2-5. Major direct operating costs are associated with sorbent purchase and maintenance of monitoring instruments. The total annualized cost (including capital recovery and downtime) is $2,580,000.

5.2.6 Best Acid Gas Control

5.2.6.1 Description of Modifications. To achieve 70 percent reduction of SO_2 and 90 percent reduction of HCl, a new spray dryer/fabric filter system will be installed on each combustor. Lime slurry will be introduced in each spray dryer at a 2.5:1 calcium-to-acid gas molar ratio.

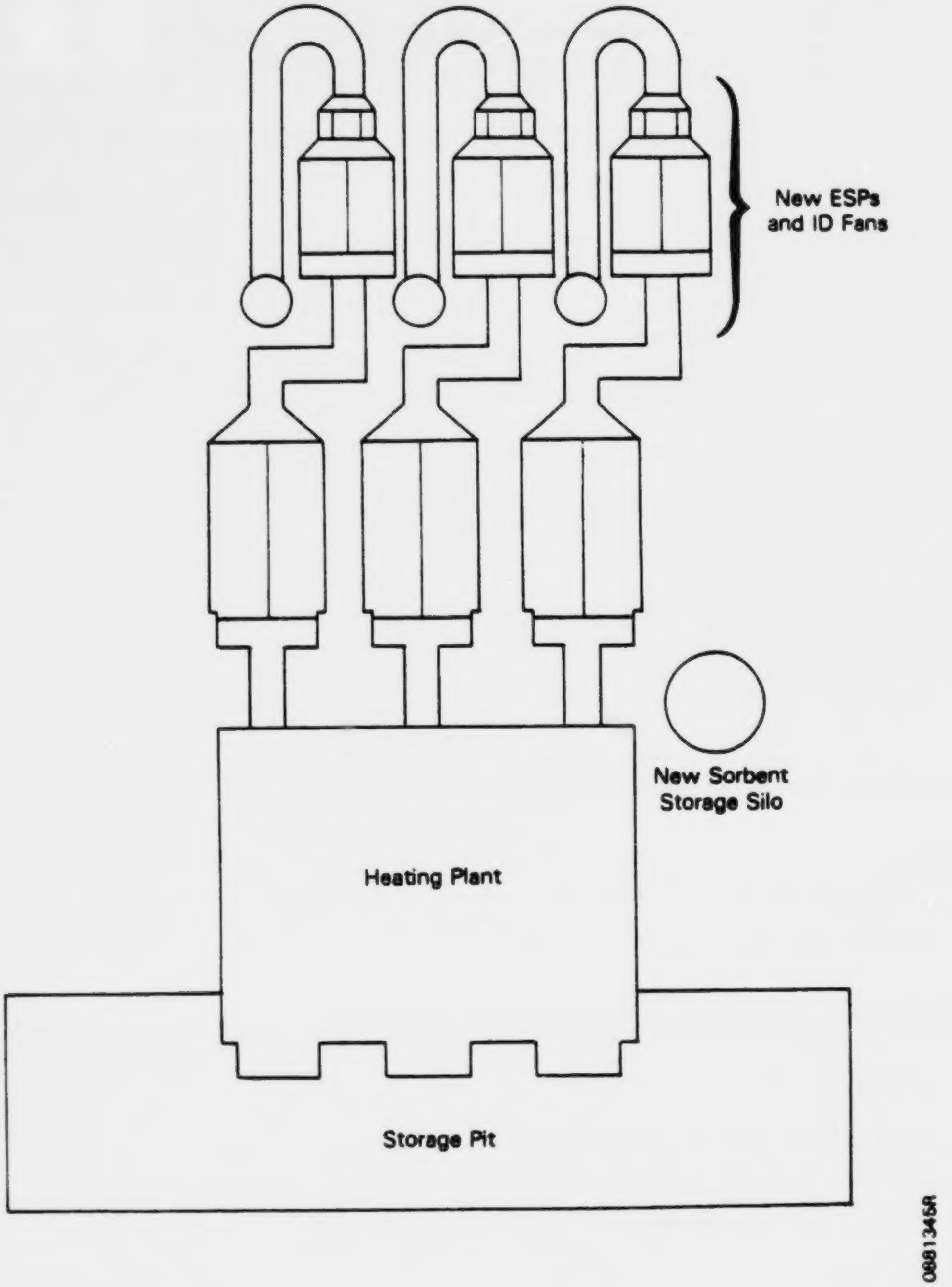

Figure 5.2-6. Plot Plan for Duct Sorbent Injection Equipment Arrangement.

TABLE 5.2-4 PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ESP
(Three units of 360 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas Control	
Equipment	560
Access/Congestion Cost	56
Particulate Control	
Equipment	1,780
Access/Congestion Cost	444
New Flue Gas Ducting	
Ducting Cost	229
Access/Congestion Cost	63
Other Equipment	
Temperature Control[a]	597
Fan	569
Stacks	0
Demolition/relocation	0
Total	4,300
Indirect Costs and Contingencies	1,730
Monitoring Equipment[b]	771
TOTAL CAPITAL COST	6,800
DOWNTIME COST	1,270
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	1,060

[a] Based on high access and congestion for installation.

[b] Turnkey.

TABLE 5.2-5 PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ESP
(Three units of 360 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Operating Labor	90
Supervision	35
Maintenance Labor	40
Maintenance Materials	72
Electricity	44
Water	6
Lime	391
Waste Disposal	157
Monitors	309
Total	1,140
INDIRECT COSTS:	
Overhead	142
Taxes, Insurance, and Administration	241
Capital Recovery and Downtime	1,060
Total	1,440
TOTAL ANNUALIZED COST	2,580

Lime will be slurried in the additional 13 gpm of water needed to cool the flue gas to 300°F.

The proposed equipment layout is illustrated in Figure 5.2-7. This sketch shows the location of the lime receiving, storage, and slurry area which will serve all three spray dryers. A fabric filter with 23,900 effective square feet of cloth (net air-to-cloth ratio of 4:1) will be installed following each spray dryer. The increased pressure drop of fabric filters over existing ESP's will require new ID fans for each unit as well. An estimated 750 total feet of new duct will be needed to access the existing stacks. New monitoring instruments for HCl, SO_2, CO_2, and opacity will be installed.

The new equipment will be located behind the existing stacks. New duct will be tied in just ahead of the existing ESP's which will be abandoned in place. Downtime for duct tie-in for each new unit is expected to be 1 month.

5.2.6.2 Environmental Performance. CDD/CDF emission reductions to 5 ng/dscm are expected. Emissions of particulate matter will be maintained at 0.01 gr/dscf. Acid gases will be reduced to 90 percent for SO_2 and 97 percent of HCl.

5.2.6.3 Costs. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 5.2-6. Total capital cost is estimated to be $21,000,000. This figure includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion, few additional facilities and no purchased land. Downtime cost (lost revenue) is estimated to be $1,270,000.

Annual operating and maintenance costs are presented in Table 5.2-7. The most significant O&M expenses include replacement bags for the fabric filters and electricity for the larger ID fan needed due to the increased pressure drop across the fabric filters. Total annualized cost, including capital recovery and downtime is $5,790,000.

5.2.7 Summary of Control Options

5.2.7.1 Description of Control Options. The control technologies described in the previous sections have been combined into seven retrofit

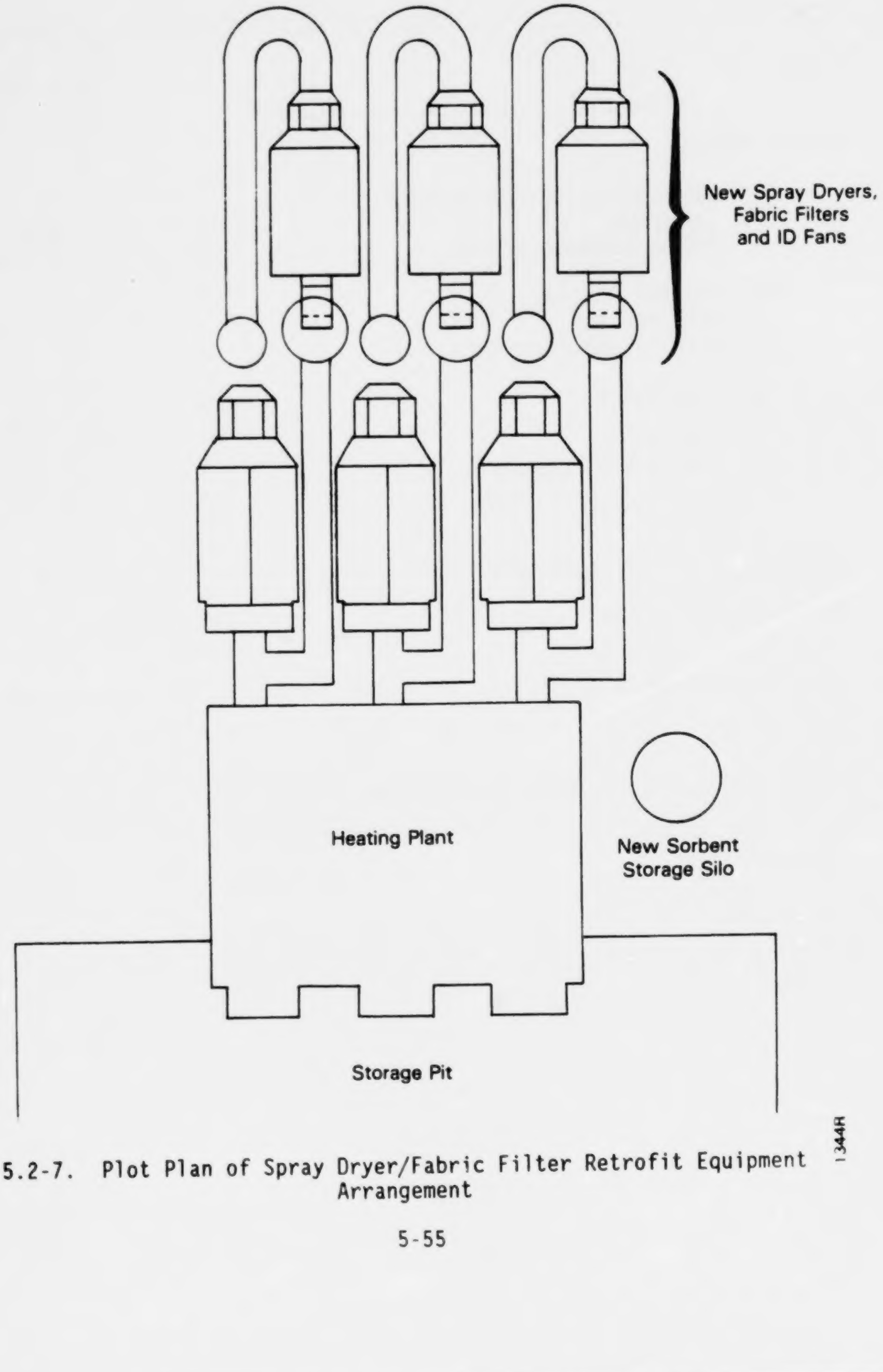

Figure 5.2-7. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement

TABLE 5.2-6 PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Three units of 360 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas and Particulate Control	
Equipment	9,410
Access/Congestion Cost	2,350
New Flue Gas Ducting	
Ducting Cost	333
Access/Congestion Cost	83
Other Equipment	
Fan	454
Stacks	0
Demolition/relocation	0
Total	12,600
Indirect Costs and Contingencies	7,530
Monitoring Equipment[a]	859
TOTAL CAPITAL COST	21,000
DOWNTIME COST	1,270
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	2,930

[a] Turnkey.

TABLE 5.2-7 PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Three units of 360 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Operating Labor	144
Supervision	22
Maintenance Labor	79
Maintenance Materials	323[a]
Electricity	282
Compressed Air	40
Water	9
Lime	324
Waste Disposal	208
Monitors	322
Total	1,750
INDIRECT COSTS:	
Overhead	298
Taxes, Insurance, and Administration	806
Capital Recovery and Downtime	2,930
Total	4,030
TOTAL ANNUALIZED COST	5,790

[a] Includes bag replacement of $70,000 per year.

emission control options. These options are discussed in detail in Section 3.0. Table 5.2-8 summarizes the combustion, particulate control and acid gas control technologies described in Sections 5.2.3 through 5.2.6 that were combined for each of the control options. It should be noted that since the model plant achieves 0.01 gr/dscf and practices good combustion at baseline, Options 2 and 3 are identical to Option 1.

5.2.7.2 Environmental Performance. The performance of each control option is summarized in Table 5.2-9. For each pollutant the table presents both the pollutant concentrations and annual emissions. The greatest reduction in total CDD/CDF, and acid gas emissions is achieved by addition of the spray dryer/fabric filter systems. Since good combustion is practiced at baseline, CO emissions are unchanged. Similarly, best particulate control is practiced at baseline, so PM emissions are unchanged. Spray drying and dry sorbent injection increase solid waste disposal requirements by 5 percent and 6 percent, respectively.

5.2.7.3 Costs. The total annualized cost of each option is presented in Table 5.2-10. Cost of control increases with increasing level of control for CDD/CDF and acid gases. However, duct sorbent injection is more cost effective than spray drying, on a per pound of reduction basis. Duct sorbent injection achieves a 75 percent reduction in CDD/CDF for one-third to one-half the cost of 98 percent reduction by spray drying.

5.2.7.4 Energy Impacts. Table 5.2-11 presents a summary of the energy impacts associated with the control options. The electrical use figures take into account the cost savings of not operating the existing ESP's under Options 6 and 7. There is no increase in auxiliary fuel use because auxiliary burners are in place on the model plant and are used under baseline operation.

TABLE 5.2-8 SUMMARY OF CONTROL OPTIONS FOR MID-SIZE MASS BURN WATERWALL COMBUSTOR

			Particulate Matter Control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing Rebuilt ESP	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion and Temperature Control	X	X					
3. Best PM Control and Combustion and Temperature Control	X	X					
4. Good Acid Gas Control, Best PM Control Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/Temperature Control	X	X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X			X		X

TABLE 5.2-9 ENVIRONMENTAL PERFORMANCE SUMMARY FOR MID-SIZE MASS BURN WATERWALL MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 360 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	200	200	200	100	50	50	5	5
Mg/yr	2.8E-4	2.8E-4	2.8E-4	2.8E-4	7.0E-5	7.0E-5	7.0E-6	7.0E-6
% Reduction vs. Baseline	--	0	0	0	75	75	98	98
CO Emissions								
(ppmv)	50	50	50	50	50	50	50	50
Mg/yr	87	87	87	87	87	87	87	87
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	32	32	32	32	32	32	32	32
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	797	797	797	797	478	478	75	75
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	1140	1140	1140	1140	228	228	32	32
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	324	324	324	324	343	343	349	349
Mg/yr	98,200	98,200	98,200	98,200	103,900	103,900	105,700	105,700
% Increase vs. Baseline	--	0	0	0	6	6	8	8

[a] All flue gas concentrations are reported on a 7% O_2 basis. Standard and normal conditions are both 1 atmosphere and 70°F.

TABLE 5.2-10 COST SUMMARY FOR MID-SIZE MASS BURN WATERWALL MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 360 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	86	86	86	6,800	6,890	21,000	21,100
Downtime Cost	0	0	0	1,270	1,270	1,270	1,270
Annualized Capital and Downtime Cost	11	11	11	1,060	1,070	2,930	2,940
Direct O&M Cost	84	84	84	1,140	1,230	1,750	1,830
Total Annual Cost	148	148	148	2,580	2,730	5,790	5,940
Cost Effectiveness ($/ton MSW)	0.41	0.41	0.41	7.17	7.58	16.10	16.50
Facility Downtime (Months)	0	0	0	1	1	1	1
Total Compliance Time (Months)	3	3	13	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs given in December 1987 dollars.

TABLE 5.2-11 ENERGY IMPACTS FOR MID-SIZE MASS BURN WATERWALL COMBUSTOR CONTROL OPTIONS[a]
(Three units of 360 tpd each)

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	0	0
4	967	0
5	967	0
6	6,150[b]	0
7	6,150[b]	0

[a] Increase from baseline consumption.

[b] Excludes electricity credit of not operating the ESP's.

5.3 SMALL MASS BURN WATERWALL COMBUSTOR

This section presents the case study results for a small mass burn waterwall municipal waste combustor (MWC). This model plant represents MWC's with individual unit capacities smaller than 250 tpd. As shown in Table 5.0-1, there are 9 known plants in this subcategory, including the oldest mass burn waterwall facility in the United States (Norfolk Naval Station) and several new facilities with state-of-the-art design and controls. Seven of the nine facilities are equipped with ESP's; one facility has a spray dryer with fabric filter, and one uses duct lime injection with fabric filters for control of acid gas and PM.

Section 5.3.1 describes the New Hanover County facility, which was visited in order to gather information for model development. Section 5.3.2 describes the model plant, including baseline emission performance estimates. Sections 5.3.3 through 5.3.7 detail the retrofit modifications, estimated emission reductions, and costs associated with each retrofit control option. Section 5.3.8 summarizes the control options, which are discussed in more detail in Section 3.0 of this report.

5.3.1 Description of New Hanover County MWC[4]

5.3.1.1 Combustor Design and Operation. The New Hanover County, North Carolina facility is comprised of two identical waterwall mass-burn furnaces (boilers), each with a design capacity of 100 tons of municipal solid waste (MSW) per day. Table 5.3-1 presents key design data for the facility. The facility has been in operation since 1984 and processes an estimated 55 percent of the county's generated wastes, burning waste 7-days/week, 24-hours/day. Each unit is brought off line monthly for maintenances and for removing soot from the convective section of the boiler. This "clean out" period typically lasts 8 hours; however, in cases where there is low soot build-up, the boilers can be cleaned in 3 to 4 hours. The facility has a projected 30-year remaining life.

The boilers and reciprocating grate stokers were built by E. Keeler Company and Detroit Stoker, respectively. The boilers are tube and tile construction rather than membrane wall. Both were shop-fabricated in two sections and sent to the facility for assembly. Only MSW is fired in the boilers. Each boiler is capable of producing 26,144 pounds per hour of

TABLE 5.3-1. NEW HANOVER DESIGN DATA

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 2
Combustor Unit Capacity	- 100 tpd
Grate Manufacturer	- Detroit Stoker
Boiler Manufacturer	- Keeler
Emission Controls:	
Type	- Electrostatic Precipitator
Manufacturer	- United McGill
Number of Fields	- 2
Inlet design particulate loading	- 5.0 gr/dscf
Operating Temperature	- 425 to 550°F
Design Collection Efficiency	- 99 percent
Particulate Emission Limit	- 0.05 gr/dscf
Gas Flow	
Normal Conditions	- 26,000 acfm at 425°F
Upset Conditions	- 40,000 acfm at 550°F
Total Plate Area	- 6,860 ft^2
SCA at 26,000 acfm	- 264 ft^2/1,000 acfm
SCA at 40,000 acfm	- 172 ft^2/1,000 acfm
Gas Residence Time at 26,000 acfm	- 4.5 seconds
Gas Residence Time at 40,000 acfm	- 2.9 seconds

superheated steam at 525 psig and 650^0F. Each unit currently contains a bare tube economizer which is not an integral part of the boiler. The economizer preheats boiler makeup water to about 250^0F while cooling the flue gas to 450^0F.

The facility operates on a four shift system commonly used by utility power plants. Each shift includes one shift supervisor, one plant operator, two assistant plant operators, and one crane operator. The plant operator is responsible for control room functions. The assistant plant operators perform various functions in the boiler areas as well as driving the ash trucks to the landfill. Five mechanics are available during the daytime hours for maintenance and repairs of the boiler facility. For the nighttime shifts, one of the operators is skilled in maintaining and repairing the boiler facility. During the downtime days, operators will assist the mechanics in repairing the equipment.

Garbage trucks dump household waste each day into a 1,700 cubic yard refuse pit. The refuse pit is capable of storing a 3-day supply of MSW at 200 tpd. One overhead crane equipped with a grapple is used to transfer MSW from the pit to the charging hopper of each boiler. A second crane is available for standby service. From the charging hopper, the wastes move down through the feed chute to the feed table, where a hydraulic ram feeds the boiler. A cutoff gate is located between the charging hopper and the feed chute. There are two Detroit Stoker reciprocating grate sections in each unit; each section is 8 feet, 2 inches wide by 11 feet, 2 inches long. Each grate section contains a single underfire air plenum. Approximately 70 percent of primary air is supplied to the upper grate section and 30 percent to the lower section. There is a vertical grate step of approximately 1.5 feet between the grate sections.

The boilers contain two rows of overfire air nozzles on the front wall and two rows on the rear wall. Sidewall air is also injected just above the grate elevation on both sidewalls to provide temperature control and prevent slagging. The overfire air nozzles are 2 inches in diameter. The front to rear wall distance across the furnace is 14 feet. The overfire air fan has capacity to operate at 50 percent of total air, but the normal operating range is 25 to 30 percent of total air. Each unit has separate forced-draft fans for underfire and overfire air supply. Flue gas oxygen is monitored by an analyzer at the economizer outlet. The facility operates each boiler at an O_2 concentration of 10 percent (wet basis), or approximately 100 percent excess air.

The bottom ash is sent directly to water-filled residue conveyor troughs. Ash collected in a hopper below the economizer and in the ESP's is conveyed by a dry mechanical chain fly ash conveyor. The fly ash is then combined with the bottom ash in the water-filled residue conveyor troughs before it is dumped into ash hauling trucks. The trucks transport the ash to a local landfill for disposal. New Hanover County currently charges a flat tipping fee of $3.68/cubic yard ($22/ton) on the ash. The landfill is double-lined and incorporates a leachate collection system. An average of 7 truck loads of ash are sent to the landfill per day.

The facility sells a portion of the steam produced in the boilers to W. R. Grace Chemical Company. The steam price is equivalent to 110 percent of the cost of the least expensive fossil fuel available. Because W. R. Grace Chemical Company requires 250 psig steam, a steam turbine on-site reduces the steam pressure while generating electricity. The facility has a 5-year contract with W. R. Grace.

Excess steam capacity is used to generate electricity by a second steam turbine. The steam turbine is rated at 4 MW and produces about 2000 kw per year. For 1986 and 1987, the plant generated about 12.2 million kwh per year. All electricity not used on site is sold to Carolina Power and Light at their cogeneration rate. The steam used to produce electricity is condensed and sent to the demineralizer tank for reuse as boiler makeup. However, condensate from the steam sold to W. R. Grace is not returned to the facility since the condensate contains high levels of nitrates. Therefore, additional feed water is provided to the facility by on-site wells. The feedwater supply system has the capacity for 100 percent water makeup.

Control loops are in place to maintain constant steam drum pressure through modulation of undergrate air. Grate speed and ram speed are also varied to maintain desired furnace temperatures, and constant furnace pressure (-0.5 inch water gage) is achieved by ID fan controls. Detroit Stoker provided an electronic feed control which now has a manual override. Overfire air adjustments are manual, with variations to control furnace temperature.

Since start-up, the facility has experienced continual flame impingement, erosion, and corrosion problems on the steam drum and convective section. To alleviate some of the problems, the facility coated the convective tubes with castable refractory. Furthermore, extensive modifications are being evaluated by the facility and the County to eliminate these problems. Some of the options being considered by the County's consultant include:

1. increasing boiler height by 14 to 15 feet through addition of a membrane wall,
2. segmenting underfire air supplies and providing individual plenum controls,
3. installing furnace arches and redesigning overfire air firing patterns, and
4. adding steam coil air preheaters.

The modifications will be implemented by bringing one boiler down and keeping one on-line, with an estimated downtime of three months per unit.

In addition to the modifications to the existing boilers, construction of a third mass-burn waterwall boiler is in planning stages. The new boiler will process 250 tpd of MSW and will be equipped with natural gas auxiliary burners. The facility has easy access to natural gas, since the main gas line is about 200 feet from the facility. The new boiler will also be equipped with a Bailey Network 90 controller and a spray dryer and fabric filter emission control.

Start-up of the existing boilers is accomplished without any auxiliary fuels. Before start-up, several grapple loads of the driest material available in the refuse pit is delivered to the feed chute by the crane operator. The hydraulic ram charges part of the waste onto the burning grate. The material on the grate is ignited by hand. Undergrate air flows are adjusted until burning is self-sustaining.

5.3.1.2 Emission Control System Design and Operation. Two identical United McGill 2-field ESP's are used to control particulate matter (PM) emissions. The flue gas leaving each ESP is ducted to a common stack. Both

ESP's contain flat plates. Programmable controls are used to maintain a stable corona. Opacity monitors are located at the exit of each ESP's to monitor smoke. The facility cannot exceed a 20 percent opacity limit imposed by the State. The facility reported opacity levels less than 10 percent during normal operation.

Flue gas enters the ESP's at a temperature of 425°F and leaves at about 405°F. The inlet flue gas temperature is not controlled but is monitored with a thermocouple located at the outlet of the economizer. The ESP's have experienced some corrosion on cool surfaces around the electrical connection boxes. According to the Bolin Chart, the flue gas temperatures between 405 and 425°F are within the temperature range of 300 to 600°F for minimal corrosion. Below 300°F, electochemical corrosion will likely occur; whereas for flue gas temperatures above 600°F, corrosion caused by chlorides and iron sulphate reduction will take place.

Each ESP is designed to handle flue gas flow rates of 26,000 acfm at 425°F based on MSW with a heating value of 5,000 Btu/lb (normal conditions) and 40,000 acfm at 550°F based on an MSW heating value of 3,750 Btu/lb (upset conditions). The ESP can remove 99 percent of the particulates during normal conditions, resulting in outlet PM emissions of 0.05 gr/dscf corrected to 12 percent CO_2. The specific collection area (SCA) is 264 and 172 ft^2/1000 acfm during normal and upset conditions, respectively. The velocity inside the ESP is 3.5 and 5.3 feet per second during normal and upset conditions. At normal conditions, the gas residence time is 4.5 seconds, while at upset conditions, the gas residence time is 2.9 seconds.

Each ESP is about 16 feet long by 14 feet wide by 15 feet tall. United McGill provided additional room for adding another field. The facility said that United McGill agreed to add this field at no costs if PM emissions were above the Subpart E emission level of 0.08 gr/dscf during initial PM testing. Initial PM testing conducted on August 1984 using EPA Method 5 showed that PM emissions from the exit of each ESP were below this level, ranging from 0.03 to 0.04 gr/dscf corrected at 12 percent CO_2.

The electrical field gradient at the discharge electrodes is 8.25 kV/inch and the average electrical field gradient at the grounded collecting electrodes is 24 kV/inch. Voltage applied to the emitting plates is 26 kV. Distance between emitting plates and collecting plates is 3.15 inches. Corona power of each ESP is 152 watts/1000 cfm. Each field has one transformer/rectifier (T/R) set.

For removing particulates caught by the ESP's, the whole field is rapped. During rapping, a visible plume above the stack is observed by the operators. The consultant at this facility indicated that if his company were to build another plant, they would design the ESP's to rap each plate individually instead of the whole field for minimizing smoke emissions.

The operators visually inspect the ESP's monthly for potential corrosion or performance problems. No problems have been observed by the operators to date.

5.3.2 Description of Model Plant

5.3.2.1 Combustor Design and Operation. A list of facilities represented by this model plant is presented in Table 5.0-1. The 9 operating facilities include units ranging in size from 50 to 180 tpd. All of the plants are comprised of two individual combustors. Based on the distributions of unit sizes in the population, a representative model plant consists of two units, each with a rated capacity of 100 tpd. The boilers are assumed to use tube and tile constructed waterwalls. It is assumed that the model plant burns MSW at full capacity on a continuous operating schedule. Table 5.3-2 presents baseline design and operating data for the model plant. Figure 5.3-1 shows a plot plan of the model plant.

The average age of the 9 facilities in this population is 7 years. Based on available information regarding design, operation/control, and verification practices in place at the existing facilities, a representative configuration for the model plant includes the following features. Waste is introduced to the units by hydraulic ram feeders. Each unit contains three individual grate sections. Each grate section has two underfire air plenums which distribute primary air to the grate. Changes in underfire air distribution are made by manual adjustment. The damper on the forced-draft

TABLE 5.3-2 MODEL PLANT BASELINE DATA FOR SMALL MASS BURN WATERWALL COMBUSTOR

Combustor:	
Type	- Mass Burn Waterwall
Number of Combustors	- 2
Combustor Unit Capacity	- 100 tpd
Emission Controls	
Type	- Electrostatic Precipitator
Number of Fields	- 2
Inlet Temperature	- 500^oF
Collection Efficiency	- 98 percent
Gas Flow	- 24,000 acfm
Total Plate Area	- 5,830 ft^2
SCA at 24,000 cfm	- 243 ft^2/1,000 acfm
Emissions:[a]	
CDD/CDF	- 2,000 ng/dscm
PM (stack)	- 0.05 gr/dscf[b]
CO	- 400 ppmv
HCl	- 500 ppmv
SO_2	- 200 ppmv
Stack Parameters:	
Height	- 140 feet
Diameter	- 5 feet
Operating Data:	
Remaining Plant Life	- $\geq$ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $3,130,000/year

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[a] All emissions are dry, corrected to 7 percent O_2.

[b] Inlet PM emissions to the ESP are 2.0 gr/dscf at 7 percent O_2.

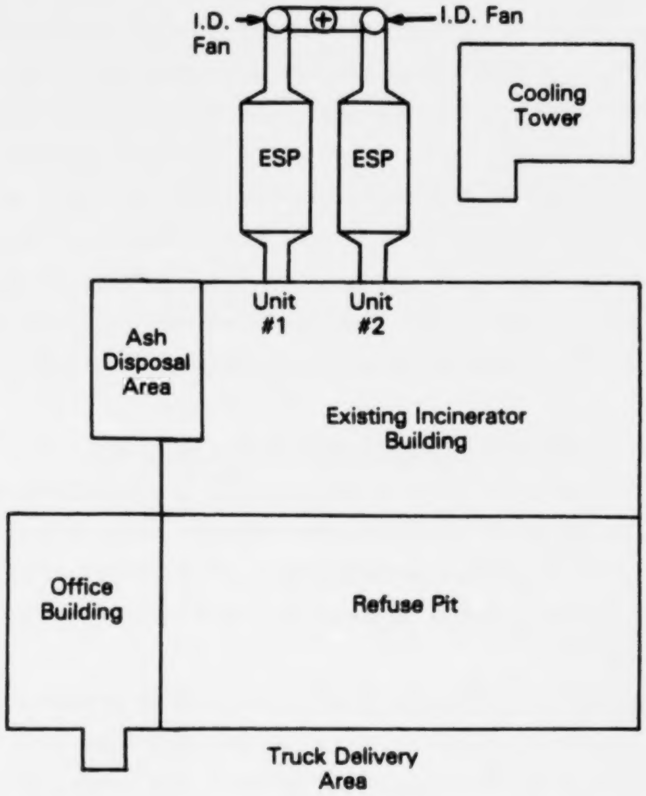

Figure 5.3-1. Plot plan of the model plant.

fan is automatically controlled based on a desired steam flow set point. Each unit is designed to operate at 80 percent excess air, with 70 percent of total air as underfire air and 30 percent as overfire air. At 80 percent excess air, the total combustion air flow is 10,000 scfm per unit, with 7,000 scfm underfire air and 3,000 scfm overfire air. Total gas flow exiting the combustor is approximately 12,200 scfm (11,200 dscfm), including all flue gas products.

Overfire air is supplied through three rows of high pressure nozzles. Two of the nozzle rows are located on the furnace front wall and a single row is located on the rear wall. It is assumed that the units do not have auxiliary fuel firing capacity. The model plant utilizes continuous oxygen monitors, which are located at the economizer outlet, but does not monitor CO. Typical of all heat recovery units, flue gas temperature measurements are made in the upper furnace just upstream of the superheater and at the exit of the economizer (inlet to the flue gas cleaning equipment). It is assumed that the flue gas temperature at the economizer outlet is maintained at 500°F.

5.3.2.2 Emission Control System Design and Operation. As shown in Table 5.0-1, 8 of the 9 plants in this subcategory are equipped with ESP's. The New Hanover plant has a 2-field ESP with PM emissions of 0.05 gr/dscf adjusted to 7 percent O_2. For the model plant, it will be assumed that most existing plants are similar to New Hanover from a particulate control performance standpoint.

5.3.2.3 Environmental Baseline. Table 5.3-2 also presents baseline emissions data for the model plant. It is assumed that the overfire air system does not provide adequate mixing to achieve low organics and CO emissions. As a result, baseline uncontrolled CDD/CDF emissions are established at 2000 ng/dscm, and baseline CO emissions are 400 ppmv, corrected to 7 percent O_2. Typical of mass burn waterwall MWC's, an average uncontrolled particulate rate of 2.0 gr/dscf is selected for the model plant. Uncontrolled emissions of HCl and SO_2 are assumed to be 500 ppmv and 200 ppmv, respectively. It is assumed that the combustion process results in a waste volume reduction of 90 percent (70 percent by weight).

5.3.3 Good Combustion

The following sections describe retrofits necessary to bring the performance of the model plant to a level which is representative of good combustion practice. The retrofits address the design, operation/control, and verification elements of good combustion practice.

5.3.3.1 Description of Modifications.

Overfire Air System. The model requires a redesign of the overfire air system to provide good mixing patterns in the upper furnace. Flow modeling studies are required to establish the new jet sizes and configuration. It is assumed that the existing fan has adequate capacity to provide the needed quantities of air. Because the waterwalls are assumed to be tube and tile construction rather than membrane wall, relocation of overfire air nozzles, if necessary, will not require modification to the waterwall tubes. Equipment needed for the new system includes ducting, dampers, nozzles, and pressure monitors. Improved mixing conditions will be verified through in-furnace profiling of CO, O_2, and temperature, and through the use of continuous monitors.

Underfire Air System. Monitors will be added to each of the underfire air plenum supplies to provide a continuous reading of the individual plenum pressures.

Auxiliary Fuel. The model plant requires installation of auxiliary fuel burners in the combustion chamber above the highest row of overfire air nozzles. The exact placement of the burners can be established as part of the flow modeling studies. The auxiliary fuel firing capacity needed for each unit is approximately 22.5 MMBtu/hr (60 percent of full load thermal input). The auxiliary fuel burners will be used during start-up and shutdown, and during any upsets which result in abnormally high CO levels or low furnace temperatures.

O_2 Trim Loop. The model plant's combustion control system will be modified to include an O_2 trim loop. The purpose of this control loop is to adjust automatically the distribution of underfire air to the various undergrate plenums in the event that O_2 concentrations vary from established upper and lower set points. When used in combination with a steam flow/underfire air control loop, the control system will have the ability to adjust both air quantities and distributions with changing waste burning characteristics, thus improving the stability of the burning process on the grates and minimizing the occurrence and severity spikes in CO and organic emissions.

CO Monitors. New CO monitors must be installed to provide continuous verification of stable combustion conditions. The monitors should be at the same location as the existing O_2 monitors at the boiler outlet, and should include readouts and integrators.

Retrofit Considerations. It is estimated that total downtime for each unit will be 2 weeks in order to complete retrofit of the combustion systems as described above. Flow modeling studies can be completed in approximately 3 months while the units remain operational.

5.3.3.2 Environmental Performance. Through the proper application of the retrofits described above, it is estimated that emissions of CDD/CDF will be reduced to 200 ng/dscm corrected to 7 percent O_2.[5] In addition, emissions of CO are estimated to be reduced to 50 ppmv corrected to 7 percent O_2. No change in uncontrolled PM emissions is assumed to result from the modifications. No changes in HCl or SO_2 emissions are assumed since these are related to waste properties which are not expected to vary due to combustion modifications.

5.3.3.3 Costs. Cost estimates are provided in Table 5.3-3 for the combustion retrofit options described above. The total capital cost of the modifications is estimated to be \$492,000. Annual costs are presented in Table 5.3-4. Annualized capital costs are \$80,000 based on a 10 percent interest rate and a 15-year facility life. Total annualized costs, including annualized capital and yearly O&M costs, are \$205,000/year.

5.3.4 Good Particulate Control

5.3.4.1 Description of Modifications. The model plant's 2-field ESP's are well-operated and are relatively new in operation. The ESP's can reduce the inlet from 2.0 gr/dscf to 0.05 gr/dscf operating at an inlet flue gas temperature of 500°F. To cool the inlet flue gas temperature to 450°F, water will be sprayed in the ductwork between the economizer and the ESP. Demolition of the existing ductwork between the economizer and the ESP is required for installing 14 feet of larger diameter ducting with a cross-

TABLE 5.3-3. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS (Two units of 100 tpd each)

Item		Costs ($1,000)
DIRECT COSTS:		
Flow Modeling Studies		75
New Overfire Air Nozzles		25
Gas Pipeline (1/2 mile)		50
Auxiliary Gas Burners		99
CO Monitoring		44
CO Profiling		10
O_2 Trim System		25
	Total	328
INDIRECT COSTS AND CONTINGENCY		164
TOTAL CAPITAL COSTS		492
DOWNTIME COSTS		118
ANNUALIZED CAPITAL COSTS AND DOWNTIME		80

TABLE 5.3-4. PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 100 tpd each)

Item		Costs ($1,000)
DIRECT COSTS:		
Gas Consumption		15
Maintenance Labor		28
Maintenance Material		28
Operating Labor		0
	Total	71
INDIRECT COSTS:		
Overhead		34
Taxes, Insurance, and Administration		20
Capital Recovery		80
	Total	134
TOTAL ANNUALIZED COST		205

sectional area of 25 square feet. This larger diameter ducting is required to ensure that enough residence time is available for flue gas cooling (0.7 seconds). A water rate of 1.2 gpm is required to cool the flue gas to 450^{0}F for each combustor. No relocation of the ID fan is expected.

Access and congestion to install the humidification equipment are high due to the close proximity of the ESP and the economizer. Installation of the humidification equipment can be expected to be completed during the scheduled shutdown of the plant. Therefore, no unscheduled downtime is required.

Because the flue gas flow rate is reduced by humidification, it is expected that the existing ESP will be able to reduce PM emissions to 0.05 gr/dscf without adding more plate area. No modifications to the ESP's are expected. The existing opacity monitor can be reused.

5.3.4.2 Environmental Performance. Particulate matter emissions will remain unchanged from baseline. Total CDD/CDF and acid gas emissions are expected to be equal to the concentrations at the combustor exit.

5.3.4.3 Costs. Capital cost requirements for good particulate control are presented in Table 5.3-5. The major cost item is the temperature control equipment. Total capital cost is $381,000. This estimate includes purchased equipment, installation, and indirect costs such as engineering and contingencies. A high APCD congestion factor for the 14-foot ducting used for temperature control is assumed.

Annual costs are presented in Table 5.3-6 for good particulate control. The costs are dominated by annualized capital recovery and downtime. Indirect annual costs including capital recovery and downtime is $83,000. Direct operating and maintenance costs are estimated at $31,000. Thus, total annualized cost for good PM control is $115,000 per year.

5.3.5 Best Particulate Control

5.3.5.1 Description of Modification. To achieve best PM control (a PM emission level of 0.01 gr/dscf) with an inlet grain loading of 2.0 gr/dscf will require an ESP operating at 450^{0}F with a total plate area of 12,200 ft^2. The existing ESP has a total plate area of 5,830 ft^2. Therefore, to achieve an emission limit of 0.01 gr/dscf, the existing ESP will be upgraded by adding an additional plate area of 6,320 ft^2. This additional plate area

TABLE 5.3-5. PLANT CAPITAL COST FOR PARTICULATE MATTER AND TEMPERATURE CONTROLS (Two units of 100 tpd each)

Item	Costs ($1000) Good PM Control	 Best PM Control
DIRECT COSTS:		
PM Control[a]		
Equipment	0	1,140
Access/Congestion Cost	0	284
Temperature Control[b]		
Humidification Costs	291	291
Access/Congestion Costs	6	6
New Flue Gas Ducting[a]		
Ducting Costs	7	19
Access/Congestion Cost	4	7
Other Equipment		
Stacks	0	0
Demolition/Relocation	4	12
Total	312	1,760
Indirect Costs and Contingencies	69	560
Monitoring Equipment[c]	0	120
TOTAL CAPITAL COST	381	2,440
DOWNTIME COST	0	235
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	50	352

[a] Based on moderate access/congestion.

[b] Based on high access/congestion for ducting.

[c] Turnkey.

TABLE 5.3-6. PLANT ANNUAL COST FOR PARTICULATE MATTER AND TEMPERATURE CONTROLS (Two units of 100 tpd each)

Item	Costs ($1000) Good PM Control	 Best PM Control
DIRECT COSTS:		
Operating Labor	12	12
Supervision	2	2
Maintenance Labor	13	13
Maintenance Materials	4	23
Electricity	0	4
Water	1	1
Waste Disposal	0	1
Monitors	0	16
Total	31	72
INDIRECT COSTS:		
Overhead	18	30
Taxes, Insurance, and Administration	15	93
Capital Recovery and Downtime	50	352
Total	83	475
TOTAL ANNUALIZED COST	115	547

will be added as a second ESP downstream of the existing ESP. As shown in Figure 5.3-2, installation of the new ESP will not require relocation of the ID fan. In addition, 25 feet of ductwork is needed to connect the second ESP to the existing stack. A new opacity monitor will also be installed at the outlet of the second ESP.

Similar to good particulate control, demolition of ductwork between the economizer and the ESP is required for installing 14 feet of larger diameter ducting which will be used to humidify and cool the flue gas. A water rate of 1.2 gpm is required to cool the flue gas to 450^0F for each combustor. This ducting will allow gas residence time of about 0.7 seconds for gas cooling.

Access and congestion to install the humidification equipment are high due to the close proximity of the ESP and the economizer and at the ESP outlet. Access and congestion to install the new ESP plate area are moderate. Downtime for this addition will be approximately 1 month for each unit.[R]

5.3.5.2 Environmental Performance. Particulate matter emissions will be reduced from 0.05 to 0.01 gr/dscf. The additional recovered fly ash will add about 26 tons/yr to total solid waste disposal requirements. This is a 2.0 percent increase in fly ash to disposal. Emissions of CDD/CDF and acid gases are equal to the concentrations at the combustor exit.

5.3.5.3 Costs. Total capital cost requirements for best particulate control, presented in Table 5.3-5, are estimated at $2,440,000. The major cost item is the particulate control equipment. This estimate includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion factor for the ESP, high APCD congestion factor for the ducting used for temperature control, 25 feet of additional duct, and ductwork demolition. The costs are dominated by annualized capital recovery and downtime. Indirect costs including capital recovery are estimated at $352,000 per year.

Annual costs are presented in Table 5.3-6 for best particulate control. Direct O&M costs are $72,000 per year. Thus, total annualized cost for best PM control is $547,000 per year.

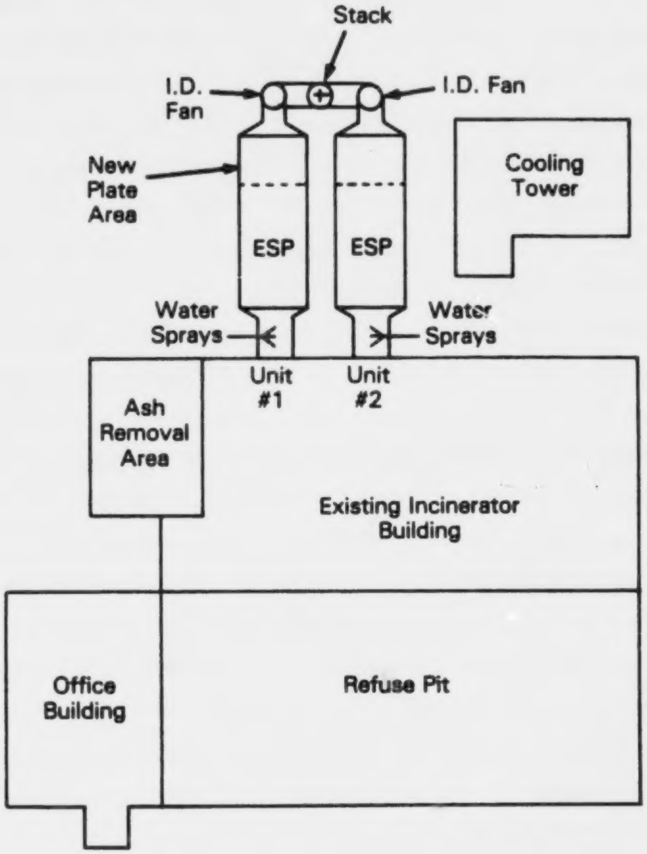

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Figure 5.3-2. Plot plan of new ESP plate area equipment arrangement.

5.3.6 Good Acid Gas Control

5.3.6.1 Description of Modification. For good acid gas control on each combustor, dry sorbent will be injected in the combustor furnace through existing overfire air ports. Duct sorbent injection was not considered because of limited space between the economizer and the ESP. Water spray nozzles will be installed as similarly discussed in Section 5.3.4.1 to provide the needed flue gas temperature reduction. A water rate of 3.6 gpm per combustor is required to cool the flue gas to $350^{o}F$. New equipment for sorbent injection includes one storage silo (one for the plant), a pneumatic sorbent system, four sorbent feed bins (two for each combustor), and four pneumatic injection nozzles (two for each combustor) Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full-load, a sorbent injection rate of 117 lb/hr is required for each combustor. Reduction in HCl and SO_2 are estimated at 80 and 40 percent, respectively.

The existing ESP will require additional plate area to reduce PM emissions to 0.01 gr/dscf. A separate ESP located in series behind the existing unit will require 6,500 ft^2 of plate area. The project also includes monitoring equipment for HCl, SO_2, CO_2, O_2, and opacity. Monitors for HCl, SO_2 and O_2 will be located in the ducting upstream of the sorbent injection area and at the outlet of the secured ESP. The opacity monitor will be located at the outlet of the second ESP. Figure 5.3-3 shows the retrofit changes. As shown in this figure, installation of a new ESP will require relocation of the ID fans. In addition, 25 feet of ductwork is needed to connect the second ESP to the existing stack. Downtime is expected to be 1 month per combustor for ductwork tie-ins.[R]

5.3.6.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 75 percent from the inlet level or 50 ng/dscm whichever is greater. Acid gas emission reductions are estimated at 80 percent for HCl and 40 percent for SO_2, respectively. As noted above, PM emissions would be reduced to 0.01 gr/dscf. An additional 1,230 tons/year of waste (sorbent and fly ash) will be added to the baseline waste disposal requirements for the plant.

5.3.6.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 5.3-7. Most of the cost is associated with the temperature and particulate control equipment. Total capital cost is

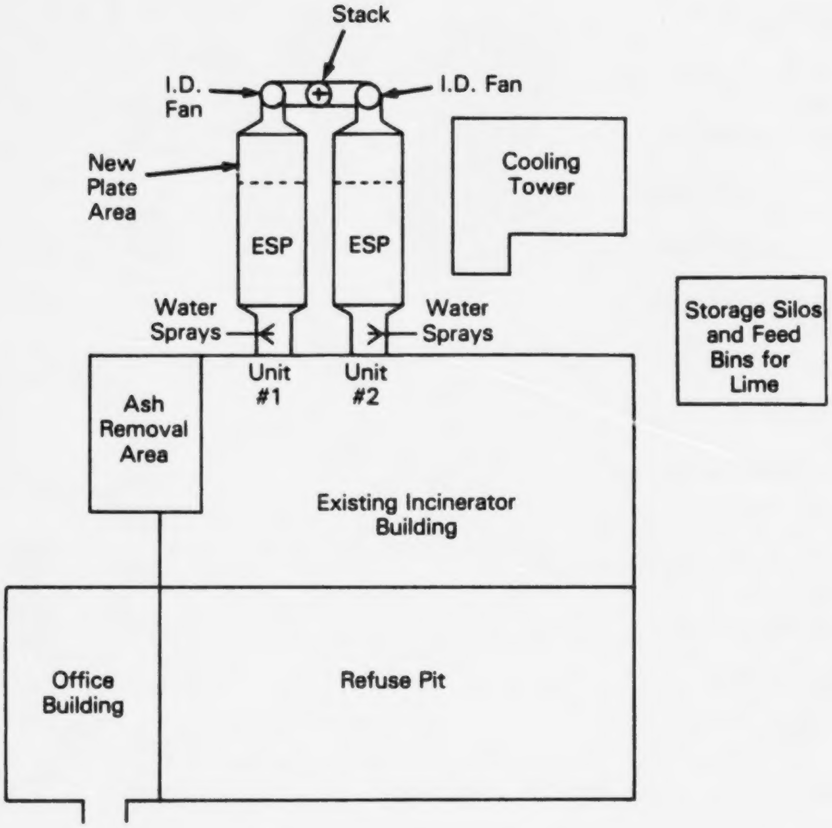

Figure 5.3-3. Plot plan of dry sorbent injection retrofit equipment arrangement.

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TABLE 5.3-7. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 100 tpd each)

Item		Costs ($1,000)
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment		384
Access/Congestion Cost		39
Particulate and Temperature Control[a,b]		
Equipment		1,470
Access/Congestion Cost		304
New Flue Gas Ducting[a]		
Ducting Cost		18
Access/Congestion Cost		7
Other Equipment		
Stacks		0
Demolition/relocation		12
	Total	2,230
Indirect Costs & Contingencies		999
Monitoring Equipment[c]		573
TOTAL CAPITAL COST		3,810
DOWNTIME COSTS		235
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		531

[a] Based on moderate access/congestion.

[b] Based on high access/congestion for ducting of temperature control.

[c] Turnkey.

$3,810,000. This cost estimate assumes a moderate APCD access/congestion level for sorbent injection and ESP upgrade, and a high APCD access/congestion for the ducting used for temperature control and ductwork demolition/fan relocation.

Annual O&M and indirect costs for good acid gas control are presented in Table 5.3-8. Major direct operating costs are monitoring equipment maintenance and line. The largest annualized cost is annualized capital recovery and downtime. The total annualized cost for the control option is $1,250,000 per year.

5.3.7 Best Acid Gas Control

5.3.7.1 Description of Modifications. To achieve greater reductions of CDD/CDF, SO_2, and HCl, a new spray dryer/fabric filter system will be installed on each combustor. The existing ESP will be demolished to make room for the spray dryer vessels. Two new smaller stacks will be included because of an extremely difficult tie-in from the fabric filter to the existing stack. However, the existing stack will not be demolished. Lime slurry will be introduced in each spray dryer at a 2.5:1 calcium-to-acid gas molar ratio. Additional water in the lime slurry of 4.7 gpm will be required to cool the flue gas to 300°F for each combustor. The proposed equipment layout is illustrated in Figure 5.3-4.

This sketch also shows the location of the lime receiving, storage, and slurry area which will serve the spray dryers. A fabric filter with 5,060 effective square feet of cloth (gross air-to-cloth ratio of 3:1) will be installed following each spray dryer. The increased pressure drop of a fabric filter over an ESP will require a new ID fan for each unit as well. An estimated 60 feet of new duct will be needed to connect the spray dryer/fabric filter to the the existing stack. New monitoring instruments for HCl, SO_2, and O_2 will be installed at both the inlet of the spray dryer and the outlet of the fabric filter. An opacity monitor will be installed at the outlet of the fabric filter. Downtime is expected to be 1 month for tie-in.[R]

5.3.7.2 Environmental Performance. CDD/CDF emission reductions of 99 percent or 5 ng/dscm, whichever is greater are expected. Emissions of PM will be reduced from 0.05 gr/dscf to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl.

TABLE 5.3-8. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 100 tpd each)

Item		Costs ($1,000)
DIRECT COSTS:		
Operating Labor		60
Supervision		16
Maintenance Labor		26
Maintenance Materials		45
Electricity		28
Water		2
Lime		75
Waste Disposal		31
Monitors		214
	Total	498
INDIRECT COSTS:		
Overhead		88
Taxes, Insurance, and Administration		129
Capital Recovery and Downtime		531
	Total	748
TOTAL ANNUALIZED COST		1,250

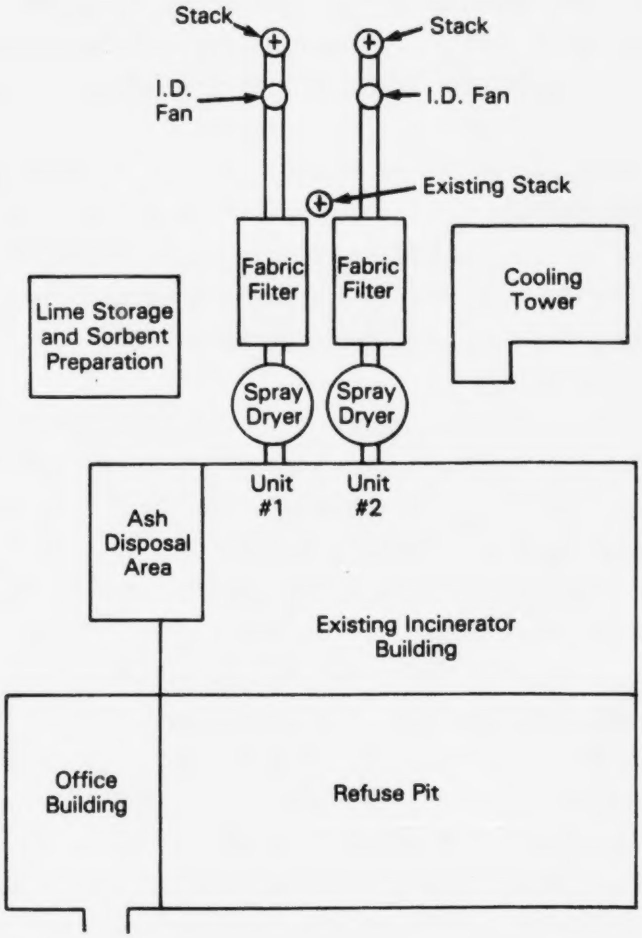

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Figure 5.3-4. Plot plan of spray dryer/fabric filter retrofit equipment arrangement.

5.3.7.3 Costs. Capital cost requirements for installing the spray dryer/fabric filter systems are presented in Table 5.3-9. Total capital cost is estimated at $8,190,000. This figure includes purchase equipment, installation, ESP demolition, addition of two new stacks, ductwork demolition, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion, 60 feet of new ductwork, and new ID fans.

Annual operating costs are presented in Table 5.3-10. Significant direct operating expenses include maintenance materials, electricity for the larger ID fan needed due to increased pressure drop access in the fabric filter, and monitoring equipment maintenance. Total annualized costs, including capital recovery and downtime, would be $2,190,000.

5.3.8 Summary of Control Options

5.3.8.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 5.3-11 summarizes the combustion, particulate control, and acid gas control technologies described in Sections 5.3.3 through 5.3.7 that were combined for each of the control options described in Section 3.0. It should be noted that since the model plant already achieves good PM control at baseline, Option 1 is identical to Option 2.

5.3.8.2 Environmental Performance. The performance of each control option is summarized in Table 5.3-12. For each pollutant, the table presents both the pollutant concentrations and annual emissions. The greatest reductions on acid gases, particulate matter, and CDD/CDF all are achieved with a spray dryer/fabric filter system. The next most effective control for all these pollutants is the dry sorbent injection technology. Dry sorbent injection technology increases the baseline solid waste disposal by about 6 percent, and the spray dryer/fabric filter system increases the baseline solid waste disposal by about 5 percent.

5.3.8.3 Costs. The total annualized cost of each option is presented in Table 5.3-13. The most expensive control option is the spray dryer/fabric filter installation with combustion modification (Option 7). The total capital cost for this option is $8,680,000 and the total annualized cost is $2,380,000. The annualized cost is roughly 7 times higher than the annualized

TABLE 5.3-9. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 100 tpd each)

Item		Costs ($1000)
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment		3,320
Access/Congestion Cost		836
New Flue Gas Ducting[a]		
Ducting Cost		29
Access/Congestion Cost		7
Other Equipment		
Fans		93
Stacks		211
Demolition/Relocation		495
	Total	4,990
Indirect Costs		1,480
Contingency		1,150
Monitoring Equipment[b]		573
TOTAL CAPITAL COSTS		8,190
DOWNTIME COSTS		235
ANNUALIZED CAPITAL RECOVERY		1,110

[a] Based on moderate access/congestion

[b] Turnkey

TABLE 5.3-10. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Two units of 100 tpd each)

Item		Costs ($1000)
DIRECT COSTS:		
Operating Labor		96
Supervision		14
Maintenance Labor		53
Maintenance Materials		99[a]
Electricity		65
Compressed Air		8
Water		2
Lime		62
Waste Disposal		40
Monitors		215
	Total	654
INDIRECT COSTS:		
Overhead		149
Taxes, Insurance, and Administration		285
Capital Recovery		1,110
	Total	1,540
TOTAL ANNUALIZED COST		2,190

[a] Includes bag replacement costs of $13,000.

TABLE 5.3-11. SUMMARY OF CONTROL OPTIONS FOR SMALL MASS BURN WATERWALL COMBUSTOR

			Particulate control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion Control	X	X					
3. Best PM Control and Combustion and Temperature Control	X	X		X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X			X		X

TABLE 5.3-12. ENVIRONMENTAL PERFORMANCE SUMMARY FOR SMALL MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS
(Two units of 100 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	3,000	200	200	200	500	50	12	5
Mg/yr[b]	7.8E-4	5.2E-5	5.2E-5	5.2E-5	1.3E-4	1.3E-5	5.2E-6	1.3E-6
% Reduction vs. Baseline	--	93	93	93	83	98	99.3	99.8
CO Emissions								
(ppmv)	400	50	50	50	400	50	400	50
Mg/yr	120	15	15	15	120	15	120	15
% Reduction vs. Baseline	--	88	88	88	0	88	0	88
PM Emissions								
(gr/dscf)	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	30	30	30	6	6	6	6	6
% Reduction vs. Baseline	--	0	0	20	20	20	20	20
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	146	146	146	146	87	87	14	14
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	212	212	212	212	42	42	6	6
% Reduction vs. Baseline	--	80	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	60	60	60	60	64	64	65	65
Mg/yr	18,140	18,140	18,140	18,170	19,260	19,260	19,610	19,610
% Increase vs. Baseline[c]	--	0	0	0.1	6	6	8	8

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis.

[b] Mass emission rates are for total plant (both combustors).

TABLE 5.3-13. COST SUMMARY FOR SMALL MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units at 100 tpd)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	873	873	2,930	3,810	4,300	8,190	8,680
Downtime Cost	118	118	235	235	235	235	235
Annualized Capital and Downtime Cost	120	120	412	543	592	1,110	1,170
Direct O&M Cost	102	102	143	498	569	654	725
Total Annual Cost	320	320	736	1,250	1,440	2,190	2,380
Cost Effectiveness ($/ton MSW)	4.80	4.80	11.00	18.80	21.60	32.90	35.70
Facility Downtime (Months)	0.5	0.5	1	1	1	1	1
Total Compliance Time (Months)	13	13	19	19	19	25	25

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[a] All costs (except cost effectiveness) given in $1000. All costs are in December 1987 dollars.

costs for option 1. Overall, both capital and annualized costs are higher for higher levels of control.

5.3.8.4 Energy Impacts. Table 5.3-14 presents a summary of the energy impacts associated with the control options. The average use figures are incremental use. The spray dryer with fabric filter control options consume the most electricity. Auxiliary fuel is fired for those options requiring combustion modifications all at the same rate of 3 billion Btu per year.

TABLE 5.3-14. ENERGY IMPACTS FOR SMALL MASS BURN WATERWALL COMBUSTOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	1.5	3.2E9
2	1.5	3.2E9
3	93.8	3.2E9
4	601	0
5	601	3.2E9
6	1,420[b]	0
7	1,420[b]	3.2E9

[a] Increase from baseline consumption.

[b] Total electrical use excludes the electrical savings of not operating the existing ESP's.

5.4 REFERENCES

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2. Epner, Radian Corporation, and Schindler, P. Energy and Environmental Research Corporation. Trip Report - Retrofit Control Site Evaluation at Saugus Resco Facility. February 16, 1989.

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6.0 REFUSE-DERIVED FUEL (RDF)-FIRED COMBUSTORS

Refuse-derived fuel (RDF) combustion practices have undergone some evolution since their inception in the 1960's and 70's. A number of obstacles related to fuel processing, feeding, and combustion had to be overcome prior to establishing RDF as a viable technology. Some of these challenges continue to exist in the current generation of RDF plants. An extensive discussion of these topics is available in a report prepared for Argonne National Laboratory, which contains a number of historical case studies describing RDF processes. This section describes the current design and operation of RDF-fired MWC's and identifies features in their design and operation which minimize air pollution.

The existing population of RDF-fired MWC's consists of 18 operating plants. Table 6.0-1 lists the RDF-fired MWC's in operation as of 1988. Most of these facilities burn primarily RDF. Several utility boilers also co-fire RDF as a supplemental fuel. Thirteen of the 18 existing plants use spreader-stoker boilers, which is the most common design for a dedicated RDF combustor. Four of the existing facilities burn RDF as a portion of total fuel input in pulverized coal (PC) boilers. One plant (Wilmington, DE) co-fires RDF with raw municipal solid waste (MSW) in a modular excess air combustor. Refuse-derived fuel is also burned in fluidized-bed combustors (FBC's). Of the 18 RDF plants, 14 have electrostatic precipitators (ESP's) for PM control and 3 are equipped with spray dryer/fabric filter systems. One has a cyclone.

Two RDF-fired model plants were developed to represent the population of existing facilities. Both model plants burn RDF as a primary fuel in spreader-stoker boilers, which are the predominant RDF-fired boiler. The first (Section 6.1) represents a plant with large (unit size > 600 tpd), and the second (Section 6.2) represents a plant with smaller units. Each model plant is equipped with an ESP for PM control.

A set of standards for classifying RDF types has been established by ASTM and is presented in Table 6.0-2. The type of RDF used is dependent on the boiler design. With few known exceptions, boilers that are designed to burn RDF as a primary fuel utilize spreader-stokers and fire RDF-3 (fluff,

TABLE 6.0-1. EXISTING RDF-FIRED FACILITIES

Plant Location	Combustor Type	No. of Units	Unit Size (tpd)	Percent RDF Fired	Year of Start-Up	Air Pollution Control Device
Lawrence, MA	Spreader/Stoker Boilers	1	1000	100%	1984	Electrostatic Precipitator
Niagara Falls, NY	Spreader/Stoker Boilers	2	1000	100%	1981	Electrostatic Precipitator
Dade County, FL	Spreader/Stoker Boilers	4	750	100%	1982	Electrostatic Precipitator
Hartford, CT	Spreader/Stoker Boilers	3	667	100%	1988	Spray Dryer/Fabric Filter
Portsmouth, VA	Spreader/Stoker Boilers	4	500	100%	1988	Electrostatic Precipitator
Columbus, OH	Spreader/Stoker Boilers	6	400	100%	1983	Electrostatic Precipitator
Red Wing, MN	Spreader/Stoker Boilers	2	360	100%	1987	Electrostatic Precipitator
Mankato, MN	Spreader/Stoker Boilers	2	360	100%	1987	Electrostatic Precipitator
Penobscot, ME	Spreader/Stoker Boilers	2	360	100%	1988	Spray Dryer/Fabric Filter
Biddeford, ME	Spreader/Stoker Boilers	2	350	100%	1988	Spray Dryer/Fabric Filter
Akron, OH	Spreader/Stoker Boilers	3	300	100%	1979	Electrostatic Precipitator
Albany, NY	Spreader/Stoker Boilers	2	300	100%	1981	Electrostatic Precipitator
Madison, WI (Oscar Meyer)	Spreader/Stoker Boilers	1	60	100%	1979	Cyclone
Madison (G&E), WI	Pulverized Coal Boilers	2	NA[a]	15%	1979	Electrostatic Precipitator
Ames, IA	Pulverized Coal Boilers	2	1 @ 700	18%	1975	Electrostatic Precipitator
			1 @ 1400	18%	1981	Electrostatic Precipitator
Lakeland, FL	Pulverized Coal Boilers	1	320	10%	1983	Electrostatic Precipitator
Baltimore (G&E), MD	Pulverized Coal Boilers	2	NA	10%	1980	Electrostatic Precipitator
Wilmington, DE	Modular Excess Air MWC	5	120	50%	1987	Electrostatic Precipitator

[a] NA - Information not available.

TABLE 6.0-2. ASTM CLASSIFICATION OF REFUSE-DERIVED FUELS

Type of RDF	Description
RDF-1 (MSW)	Municipal solid waste used as a fuel in as-discarded form, without oversize bulky waste (OBW).
RDF-2 (c-RDF)	MSW processed to coarse particle size, with or without ferrous metal separation, such that 95 percent by weight (wt %) passes through a 6-inch square mesh screen.
RDF-3 (f-RDF)	Shredded fuel derived from MSW and processed for the removal of metal, glass, and other entrained inorganics. The particle size of this material is such that 95 wt % passes through a 2-inch square mesh screen. Also called "fluff RDF."
RDF-4 (p-RDF)	Combustible-waste fraction processed into powdered form, 95 wt % passing through a 10-mesh (0.035 inch square) screen.
RDF-5 (d-RDF)	Combustible waste fraction densified (compressed) into the form of pellets, slugs, cubettes, briquettes, or some similar form.
RDF-6	Combustible-waste fraction processed into a liquid fuel (no standards developed).
RDF-7	Combustible-waste fraction processed into a gaseous fuel (no standards developed).

or f-RDF) in a semi-suspension mode. This mode of feeding is accomplished by using an air-swept distributor, which allows a portion of the feed to burn in suspension and the remainder to be burned out after falling on a horizontal traveling grate. Schematics of typical RDF spreader-stoker boilers are shown in Figures 6.1-2 and 6.2-1. The number of RDF distributors in a single unit varies directly with unit capacity. For example, each of the 1,000 tpd units at Niagara Falls, NY is equipped with 8 distributors.

Suspension-fired RDF boilers, such as pulverized coal-fired (PC) boilers, can co-fire RDF-3 or RDF-4 (powered or p-RDF). If RDF-3 is used, the fuel processing must be more extensive so that a very fine fluff results. Currently, the 4 PC boilers in operation co-fire fluff with pulverized coal. Suspension firing is usually associated with larger boilers due to the increased boiler height and retention time required for combustion to be completed in total suspension. Smaller systems firing RDF in suspension require moving or dump grates in the lower furnace to handle the falling material that does not complete combustion in suspension. Boilers co-firing RDF in suspension are generally limited to 50 percent of total heat input by RDF alone.[1] When multiple fuels are burned, the optimum balance of underfire, overfire, distributor air, and possibly burner air, is far more difficult to establish and control.

Guidelines for minimizing emissions of trace organics have been developed for RDF combustors.[2] A list of design, operation/control, and verification components associated with the guidelines is presented in Table 6.0-3. These guidelines are directed toward conventional spreader-stoker RDF boilers and may not be adapted to suspension-fired systems or FBC's. As such, the discussion of these guidelines and their application is focused on the spreader-stoker facilities.

The basic guidelines that apply to mass burn systems also apply to RDF systems. These guidelines require that:

- stable stoichiometries be maintained through proper distribution of fuel and combustion air,

- good mixing be achieved at a sufficiently high temperature to adequately destroy trace organic species, and

TABLE 6.0-3 COMPONENTS OF GUIDELINES - GOOD COMBUSTION PRACTICES FOR MINIMIZING TRACE ORGANIC EMISSIONS FROM RDF-FIRED MWC'S

Element	Component
Design	Temperature at fully mixed height
	Underfire air control
	Overfire air capacity
	Overfire air injector design
	Furnace exit gas temperature
Operation/Control	Excess Air
	Turndown restrictions
	Start-up procedures
	Use of auxiliary fuel
Verification	Oxygen in flue gas
	CO in flue gas
	Furnace temperature at fully mixed height
	Temperature at APCD inlet
	Adequate air distribution

the design and operational performance of the system be verified through monitoring or performance tests.

These design, operation/control, and verification practices are expected to minimize trace organic emissions. Recent research data indicate that CDD/CDF formation may also occur at lower temperatures in downstream portions of the system through catalytic reactions. Therefore, another guideline should be included which addresses this phenomenon. This guideline is to minimize the retention time of flue gases in the temperature window where CDD/CDF formation occurs. A discussion of basic industry practices and the application of set of guidelines is presented in the following paragraphs.

Fuel Feeding

As mentioned above, spreader-stokers generally use air-swept distributors to feed RDF into the combustion chamber. The distributors are normally adjustable so that the trajectory of the waste feed can be varied from front to rear of the furnace. Because the traveling grate moves from the rear to the front of the furnace, distributor settings are adjusted so that most of the waste lands on the rear two-thirds of the grate. This allows more time for combustion to be completed on the grate. Some traveling grates operate at a single speed, but most can be manually adjusted to accommodate variations in burning conditions.

Three common problems with RDF feeding include:

- plugging of distributors, resulting in feed interruptions and stoichiometry upsets,
- erosion of waterwall surfaces by abrasive constituents in the feed. This can sometimes be corrected by adjusting distributor trajectories, and
- high particulate carryover out of the radiation section of the boiler.

Due to the basic design of RDF feeding practices, particulate loadings are typically at least twice as high as mass burn systems and more than an order of magnitude higher than modular starved-air combustors. The higher particulate loadings may contribute to the catalytic formation of CDD/CDF.

Combustion Air

Underfire air is normally preheated and introduced beneath the grate by a single plenum. One of the newer facilities (Hartford, CT), is equipped with a multiple plenum design. This is a desirable feature which provides the operator with better ability to vary the distribution of underfire air to various portions of the fuel bed.

Overfire air is injected through rows of high-pressure nozzles, providing a zone for mixing and completion of the combustion process. The guideline specifies that systems incorporate a design capacity of 40 percent of total air as overfire air. Operational quantities are typically less than 40 percent of total, although the Red Wing, MN facility reports a normal operating ratio of 50/50. The guideline also specifies that overfire air systems provide complete coverage and penetration of the furnace cross-section to achieve good mixing. As shown in Figures 6.1-2 and 6.2-1, a typical RDF boiler has a straight wall design. As unit size increases, boiler cross-sections provide greater distances that nozzles must penetrate. Therefore, nozzle diameters, pressures, and velocities will change. A new lower furnace design used at the Biddeford, ME facility includes pinched walls through which overfire air is injected into the combustion gases. The pinched section greatly reduces the cross-sectional area of the boiler, but may increase the vertical velocities of gases in that section of the combustion chamber.

Auxiliary Fuel

All RDF-fired MWC's have the capability to co-fire additional fuels. Four of the existing spreader-stokers in Table 6.0-1 co-fire coal or wood with RDF under normal operating conditions. The remaining facilities are equipped with natural gas, fuel oil, or combination gas/oil burners. The burners are operated during start-up, shutdown, and during periods of RDF feed interruption. Because the use of auxiliary fuels is expected to be more frequent in RDF facilities than in mass burn waterwall systems, it is critical that burner design, location, and capacity be optimized.

Low Temperature Catalytic Formation of CDD/CDF

Downstream catalytic formation of CDD/CDF may be particular problem in RDF facilities for two reasons. First, existing units typically operate at ESP temperatures between 500 and 600°F, where formation has been demonstrated. Second, the higher uncontrolled particulate emission rates associated with this technology may provide more surface area for catalytic reactions to occur. However, few emissions data are available from RDF facilities to document the effects of these variables on CDD/CDF emissions.

6.1 LARGE RDF-FIRED COMBUSTOR

This section presents the case study results for a large RDF spreader-stoker facility (unit size greater than 600 tpd). As shown in Table 6.0-1, there are 4 existing facilities within this subcategory. Section 6.1.1 presents a description of the Occidental Chemical Corporation facility in Niagara Falls, NY, which was visited to gather information for model plant development. Section 6.1.2 presents a description of the model plant. Sections 6.1.3 through 6.1.7 detail the retrofit modifications, estimated performance, and costs associated with each control option. Section 6.1.8 presents a summary of the control options, which are discussed in more detail in Section 3.0 of this report.

6.1.1 Description of the Occidental RDF-Fired Facility[3]

The Occidental Energy From Waste (EFW) project began with a feasibility study in 1973. Construction began in 1978, and was essentially complete in 1980. The original project cost of $94 million was funded through a leveraged lease using Niagara County Industrial Development Bonds. A 2-1/2 year start-up and system redesign costing another $50 million was required to bring the facility to acceptable levels of continuous operation. Occidental currently leases the facility from a group of banks. However, Occidental would bear the burden of any retrofit costs brought about by regulation.

Table 6.1-1 presents design data for the EFW facilities, and Figure 6.1-1 is an overall process diagram. The facility consists of an on-site waste processing plant and 2 Foster-Wheeler boilers with Detroit Stoker air-swept distributors and traveling grates. Each unit is rated at 1,200 tons of RDF per day with a design rating of 300,000 lb/hr of superheated steam and 25 MW of electricity. Normal operating rates are currently about 230,000 lb/hr steam production per unit, which plant personnel consider to be the effective maximum continuous operating capacity of each unit. The combined effective electrical generating capacity of both units is 35 MW. Steam and electricity are delivered to the adjacent Occidental chemical plant and excess electricity sold to the local utility. The EFW facility was sized to provide the chemical plant with 100 percent of its steam requirements. Furnace particulate emissions are controlled by separate 4-field hot-side ESP's. Acid gases are not controlled.

TABLE 6.1-1. OCCIDENTAL DESIGN DATA

Combustor:	
Type	- Straight Wall Spreader Stoker
Number of Combustors	- 2
Combustor Unit Capacity	- 1,000 tpd
Emission Controls:	
Type	- Electrostatic Precipitator
Manufacturer	- Belco
Number of Fields	- 4
Inlet design particulate loading	- 3.36 gr/acf
Operating Temperature	- 550°F to 620°F
Design Collection Efficiency	- 99.77 percent
Permitted PM Emissions	- 0.03 gr/dscf at 12% CO_2[a]
Gas Flow	- 367,420 acfm @ 650°F
Total Plate Area	- 146,900 ft^2
Calculated SCA	- 400 ft^2/1,000 acfm
Gas Residence Time in ESP	- 10 seconds

[a] Reference 5.

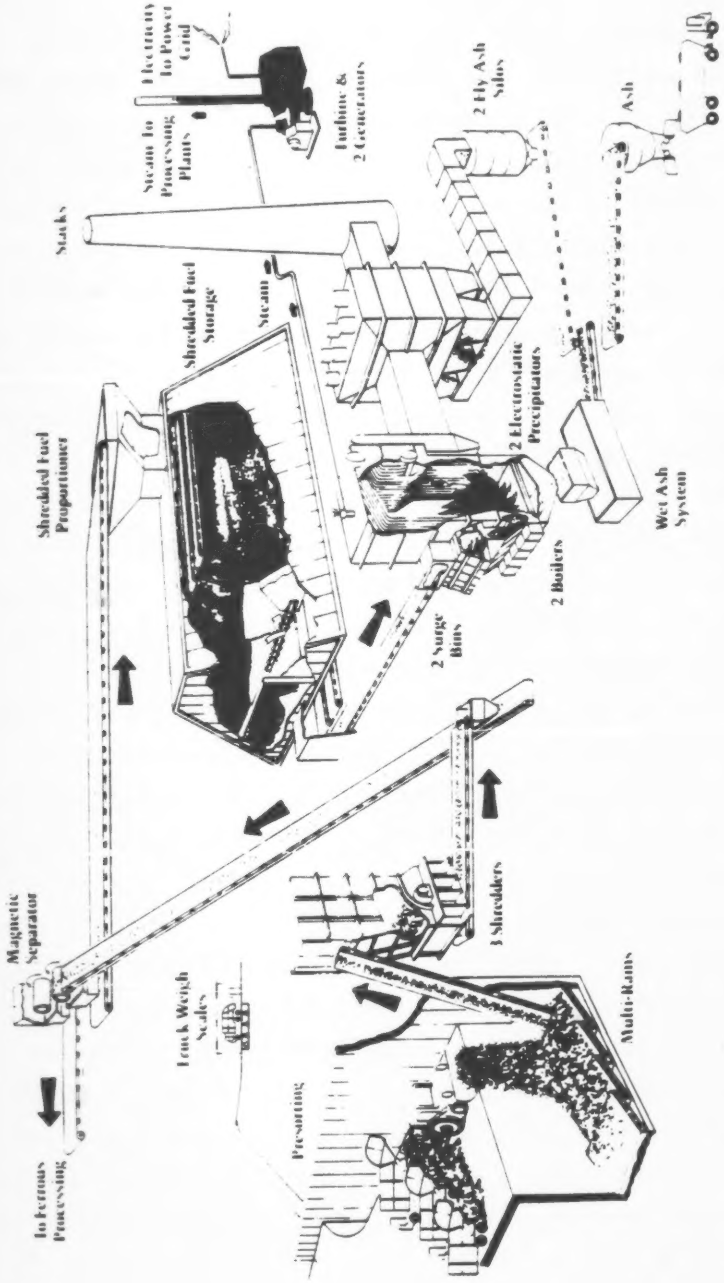

Figure 6.1-1. General process diagram of EFW facility.
(Figure provided by Occidental Chemical Corp.)

6.1.1.1 Combustor Design and Operation. The EFW facility receives municipal solid waste (MSW) and processes RDF on site. Prior to fuel processing, bulky or large non-combustible waste is separated on the tipping floor and routed to a landfill. With the exception of these items, all of the incoming waste is processed into RDF. The waste receiving pit has 2 lines of 16 hydraulic rams that push the MSW onto the shredder feed conveyors. Each of three 1,500-hp shredders (horizontal-type hammer mills) is equipped with forty 225-pound hammers. Each shredder was designed to process 70 tons of waste per hour, and currently each shreds approximately 50 to 60 tons per hour. Ferrous materials are magnetically separated and recovered. The RDF, nominally less than 4 inches in particle size, is then conveyed to the storage building. Storage capacity is 5,000 tons.

The rate of fuel fed to each boiler is controlled by surge bins. Each surge bin contains 24 augers and delivers RDF through individual feed chutes to eight 10-inch by 24-inch air swept distributors in the boilers. The distributors are located on the front wall, approximately 3 feet above the grate. The front-to-rear distribution of RDF on the grate can be adjusted by varying the air supplied to the distributors. Higher air velocities concentrate more waste on the back portion of the traveling grate. The RDF feed rate can be set to respond either to the steam flow or the steam pressure. Plant personnel indicated that it is more typical to operate in a flow control rather than a pressure control mode. The grate speed is manually set and adjusted based on the steam production rate. The fuel burns in a semi-suspension mode with combustion taking place partially in suspension in the furnace and partially on the traveling grate. The grate area is 594 square feet, and desired grate speed was reported to be 5 to 7 ft/hr. As a result of burning waste in semi-suspension, the grate area per unit weight of fuel burned is considerably less than that found in typical mass burn plants. Plant personnel reported the desired thickness of the ash bed coming off the grate to be 4 to 6 inches.

Eight coal feeders are located 7 feet, 3 inches above the RDF distributors on the front wall, but coal is not currently fired. Fuel oil and natural gas burners (4 each) are located on the rear wall about 10 feet above the RDF distributors. Natural gas is currently fired in the furnaces during start-up and during periods when RDF feeding is interrupted. Start-up is achieved with a 6-hour warm-up period on gas and refuse feed is initiated after 10 percent of steam load is attained while firing gas. The units are brought up to full load on a prescribed load curve. Each of the natural gas burners has a rated firing capacity equal to one-fourth of the unit capacity, so each furnace can be operated at full load on supplemental fuel. Both of the units also have the ability to burn hydrogen, which is available as a by-product from the adjacent chlorine plant. However, this has not been done recently.

The furnace is designed to operate at 8.2 percent excess O_2 (dry). However, the boilers are currently operated between 10 and 14 percent excess O_2 (90 to 200 percent excess air) with 70 percent of the total air supplied as underfire air. A forced-draft fan moves combustion air through a gas-to-air preheater and supplies preheated primary air to 2 laterally separated plenums located under the grate. A booster fan located downstream of the air preheater routes a portion of the preheated air to the secondary (overfire) air headers and the RDF distributor.

The overfire air system has been redesigned as a result of flow modeling studies. Rows of interlaced and opposed overfire air jets are located on the upper rear and front walls at an elevation approximately 16 feet above the RDF distributors. There are seventeen 3-inch nozzles on the front wall and twelve 3.5-inch nozzles on the rear wall. Intermediate overfire air rows are also located on the front wall and the rear wall above the RDF distributors. There are forty 2-inch diameter intermediate air nozzles in the 2 rows on the front wall and seventeen 3-inch diameter air nozzles on the rear wall. Carrier air is supplied by the booster fan to the RDF distributors on the front wall and a lower overfire air row on the rear wall. The carrier air, which is used to blow the RDF into the combustion chamber, is supplied through five 2-inch diameter nozzles per distributor. There are seventeen 3-inch diameter lower air nozzles on the rear wall, 1.5 feet below the RDF distributors. Four soot blowers are located on the rear wall between the lower and intermediate overfire air rows. Overfire air flow rates are adjusted so that the majority of the flow is introduced at the rear wall location, where the burning is concentrated.

Adjustments to total airflows are made by changing overfire air settings while maintaining constant underfire air flow rates. Excess air rates are manually set to provide the desired excess O_2 level. The boilers operate only at base load, so variations in excess air to accommodate load changes are not normally required. An oxygen trim loop is available, but the plant reports that it has not been used due to the unstable operation of the boilers. Excess air levels are operated higher than design in an attempt to keep furnace temperatures at an acceptable level and to avoid slag formation in the lower furnace and corrosion in the upper furnace.

Monitors are in place which provide continuous readings of O_2, CO, flue gas temperatures, and flue gas opacity. Oxygen and CO are measured at the boiler outlet. Flue gas temperature measurements are made at the inlet to the convective section of the boiler and between the convective section and the convective section of the boiler and between the generating section and the economizer. Opacity is measured in the stack. None of the emission monitor readings are used for process control. Occidental reported that they are able to keep CO below 100 ppm (uncorrected).

6.1.1.2 Emission Control System Design and Operation. Each combustor is equipped with a Belco 4-field ESP. Table 6.1-1 presents design and operating parameters for the ESP's. Particulate testing indicates the units are in compliance with Federal and State regulations of 0.03 gr/dscf at 12 percent O_2. Extensive inlet and outlet PM emissions data are available under varying load conditions. Flue gas temperatures entering the ESP's range from 550 to 620^{0}F. The air preheater is located downstream of the ESP's.

The ESP's are located inside the building. A duct, 2 feet 8 inches in width, connects the economizer to the ESP. This duct is approximately 20 feet long. However, it runs vertically between the economizer and ESP with only about 3 feet of clearance on the ESP side, and only 8 inches on the furnace side.

6.1.2 Description of Model Plant

6.1.1.2 Combustor Design and Operation.

Table 6.1-2 presents design data for the model plant. A model plant was selected consisting of two 1,000-tpd RDF-fired units. The model plant uses a spreader-stoker design to burn fluff RDF on a seven days per week, 24 hours per day operating schedule. The boiler configuration is a typical straight-wall design, and the stoker is a variable speed traveling grate. The equipment arrangement of the model plant is shown in Figure 6.1-2.

As with all 4 of the operating facilities, fuel feeding is accomplished by air-swept distributors. The model contains 8 RDF distributors located on the front wall of the boiler. The boilers also have 4 burners which can fire natural gas or fuel oil located on the rear wall. Each burner has a rated heat output of 105 MM Btu/hr. All 4 burners fired simultaneously can provide 100 percent of design steam load.

Each model boiler operates at 125 percent excess air with an overfire/underfire air ratio of 30/70. The RDF feed composition assumed for model plant development is presented in Chapter 2 of this report. Stoichiometric air requirements for the fuel are approximately 4.25 lb of air per lb of RDF. For a 1,000 tpd unit, the theoretical air requirements are 78,700 scfm. At 125 percent excess air, the total flue gas flow from the unit is approximately (194,200 scfm) 182,900 dscfm.

Typical of older RDF systems, underfire air is preheated by a regenerative air heater located downstream of the ESP. Underfire air is supplied beneath the traveling grate at a temperature of 350°F through 2 separate parallel plenums. The air plenums divide the grate laterally into 2 separately controlled burning regions, with each region fed by 4 RDF distributors.

The overfire air system consists of 2 nozzle rows on the boiler front wall and 2 rows on the rear wall. It is assumed that the overfire air penetration and coverage is not optimized to provide sufficient mixing. This assumption is based on an assessment of measured emissions available for the group of combustors represented by this model.

TABLE 6.1-2 MODEL PLANT BASELINE DATA FOR LARGE RDF-FIRED COMBUSTOR

Combustor:	
Type	- Spreader-Stoker
Number of Combustors	- 2
Combustor Unit Capacity	- 1,000 tpd
Emission Controls:[a]	
Type	- Electrostatic Precipitator
Number of Fields	- 4
Inlet Temperature	- $600^{o}F$
Collection Efficiency	- 99.8 percent
Gas Flow	- 392,600 acfm
Total Plate Area	- 204,000 ft^2
SCA at 392,600 acfm	- 520 ft^2/1,000 acfm
Emissions:[b]	
CDD/CDF	- 3,000 ng/dscm
PM (stack)	- 0.01 gr/dscf[c]
CO	- 200 ppmv
HCl	- 500 ppmv
SO_2	- 300 ppmv
Operating Data:	
Remaining Plant Life	- ≥ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $22,700,000/year

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[a] Per combustor.

[b] All emissions are dry, corrected to 7 percent O_2.

[c] Inlet PM emissions to the ESP are 4 gr/dscf at 7 percent O_2.

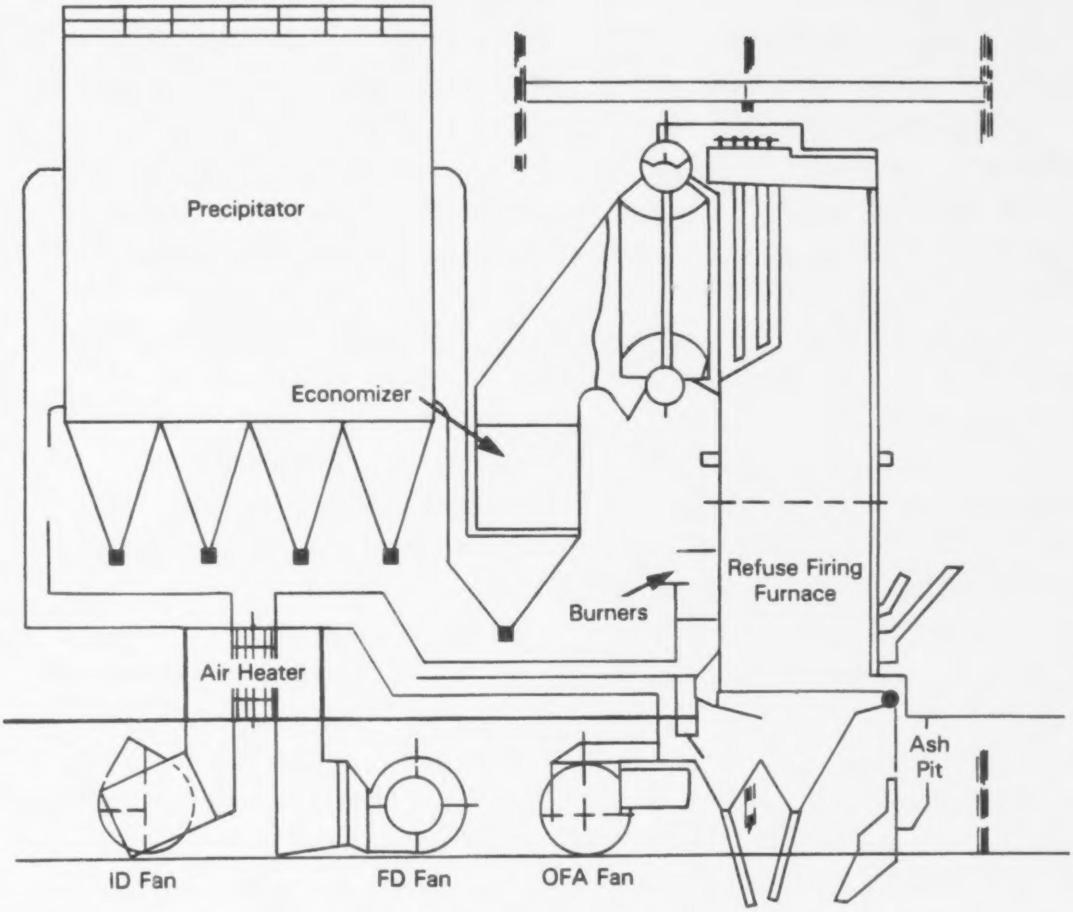

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Figure 6.1-2. Equipment arrangement of the model plant.

The combustion control system for the model plant is designed to maintain constant steam flow or steam pressure. This is accomplished by automatic adjustment of RDF feed rates. The steam flow controller sends a signal to the feeding system and the speed of the metering screws automatically adjusts to change the feed rate and raise or lower steam flow to a desired set point. Air flows are manually set and adjusted in an attempt to maintain a relatively stable excess air level. This is verified by a continuous oxygen monitor located at the economizer outlet. Flue gas temperatures are recorded in the upper portion of the radiation section of the boiler and at the economizer outlet location. The assumed economizer outlet temperature is 600°F.

6.1.2.2 Emission Control System Design and Operation. As shown in Table 6.0-1, 3 of the 4 plants in this subcategory are equipped with ESP's. The fourth plant is equipped with a spray dryer/fabric filter. The Occidental plant has a 4-field ESP with PM emissions of about 0.012 to 0.03 gr/dscf at 7 percent O_2.[5] Test data from the other two ESP-equipped MWC's indicate PM emissions of 0.01 gr/dscf or less. For the model plant, a PM emission rate of 0.01 gr/dscf is assumed.

The model plant has 2 combustors, and each is equipped with a 4-field ESP controlling PM emissions to 0.01 gr/dscf. At a gas flow of 392,600 acfm, the SCA of the ESP's is 520 ft^2/1,000 acfm. Total plate area is 204,100 square feet. An opacity monitor is located at the outlet of the ESP. The flue gas flows from the outlet of the ESP to an air preheater and then to the stack. Figure 6.1-3 shows a plot plant of the model plant. Because the combustor and ESP are located indoors, a high access and congestion level is assumed for retrofitting additional APCD's. This access and congestion level is typically of other large RDF facilities being that the combustors and the APCD's are also located indoors.

6.1.2.3 Environmental Baseline. Table 6.1-2 presents baseline emission data for the model plant. Baseline uncontrolled CDD/CDF emission levels are assumed to be 2,000 ng/dscm, corrected to 7 percent O_2. These values are measured at the exit of the boiler. It is assumed that the hot ESP increases baseline CDD/CDF emissions by 50 percent, so that stack concentrations are 3,000 ng/dscm.

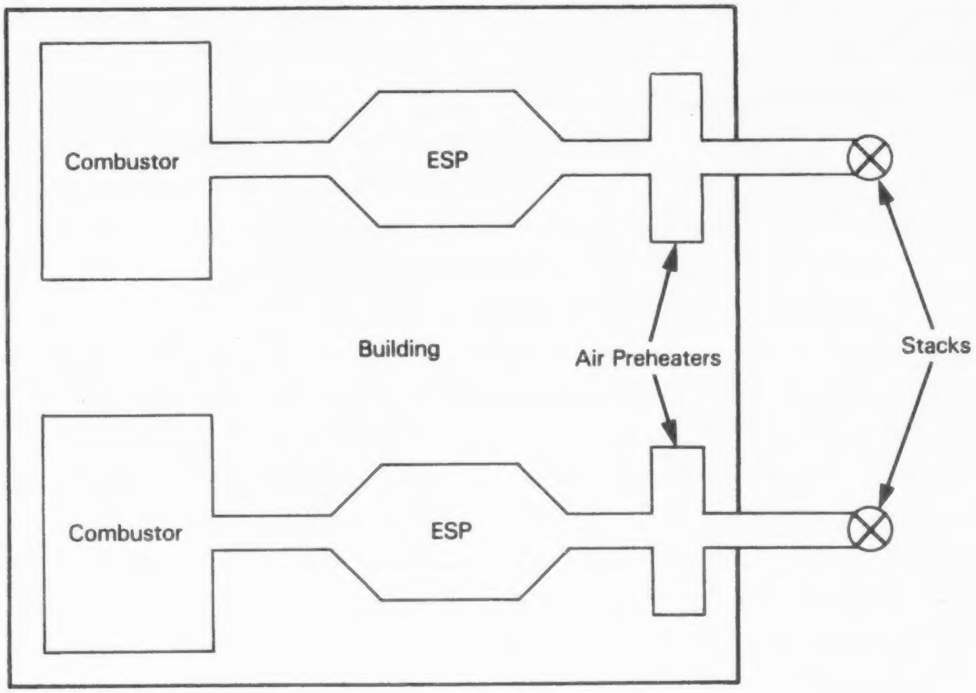

Figure 6.1-3. Plot plan for the model plant.

RDF-fired facilities generally exhibit higher uncontrolled particulate emissions than other technologies due to the manner in which the fuel is fired (semi-suspension mode). This model plant is assumed to have an uncontrolled PM emissions of 4.0 gr/dscf, corrected to 7 percent O_2.

As a result of insufficient mixing conditions, uncontrolled CO emissions from the model plant are assumed to be 200 ppmv at 7 percent O_2. Uncontrolled HCl and SO_2 emissions are estimated to be 500 and 300 ppmv at 7 percent O_2, respectively. It is assumed that the combustion process reduces waste volume by 95 percent (90 percent by weight).

6.1.3 Good Combustion and Exhaust Gas Temperature Control

The following sections describe combustion retrofits necessary to bring the performance of the model plant to a level which is representative of good combustion practices. The combustion retrofits address design, operation/control, and verification elements of good combustion practice.

6.1.3.1 Description of Modifications

Overfire Air Systems. Due to insufficient mixing conditions, the model plant will require a redesign to the overfire air system. The overfire air configuration can be established as a result of cold flow modeling studies. The size, location, and pressures for each row of nozzles will be established as a result of the study. It is assumed that the modeling results require a design that includes 2 rows of overfire air nozzles on each of the front and rear walls, and that the location of these rows will be different than in the baseline case. New nozzles locations will require modification to existing waterwall tubes so that new nozzles penetrations can be made. As part of the flow modeling studies, the location and firing patterns of the auxiliary burners should also be examined to determine the effects of firing auxiliary fuel on overfire air patterns. The modified overfire air system provides better mixing conditions and lower emissions of trace organics and CO from the furnace.

Fuel Feeding. The RDF feeding system is redesigned to include metered feeders, which provide more uniform distribution of RDF on the traveling grate and more stable burning conditions. Four separate metered feeding modules are required for each boiler, serving 2 RDF distributors each.

Excess Air Levels. As a result of the fuel feeding and combustion air modifications made to the model plant, the excess air operating level can safely be reduced to 80 percent. This contributes to reductions in CO and uncontrolled particulate emissions. In addition, reductions in excess air rates directly affect adiabatic flame temperatures. For a waste with 25 percent moisture content, flame temperatures should increase by about 150 to 200°F. At 80 percent excess air the theoretical air requirements are reduced to 142,000 scfm, and total air flows from the boilers are 158,800 scfm (147,500 dscfm).

ESP Temperature. In order to minimize the potential for CDD/CDF formation in lower temperature regions of the MWC system, the flue gas temperature entering the ESP must be reduced from 600 to 450°F. The existing ductwork is redesigned so that flue gases exit the boiler and are routed to the air heater, where available heat is transferred to combustion air supplied by the existing forced-draft fan. The flue gases are then ducted back to the ESP inlet location. New insulated ductwork is required as part of the redesign.

In order to provide flexibility with regard to ESP operating temperatures, the modifications at the model plant include installation of ducting and dampers to allow bypass of up to 100 percent of the combustion gases around the air heater. This modification provides the operators with a means of adjusting the operating temperature of the ESP, as needed. It is assumed that the system has the capability of reducing ESP inlet gas temperatures to 350°F. At normal operating conditions a percentage of the gases bypass the air heater, and the ESP inlet gas temperature is reduced to 450°F. Determination of the overall effect of these flue gas modifications will require a detailed analysis that is beyond the scope of this study. Excess air levels, combustion air inlet temperatures, flue gas velocities, and many other factors will influence combustor exit gas temperatures. However, the modifications included in this study will all contribute to improved emission performance.

Combustion Control and Monitoring. The primary control loop in the baseline plant regulates the rate of RDF feed to the boiler based on a desired steam flow. However, the modified combustion air system will also require control of air flows and distribution, temperature, and other features. Therefore, an automatic combustion controller is installed to provide full system control and monitoring. Continuous CO monitors are installed at the economizer outlet to provide verification of combustion stability. The combustion control system also ties in the existing O_2 and temperature monitors as needed to fully automate the system.

Retrofit Considerations. It is estimated that modeling studies can be completed in 3 months while the units remain on-line. During this time engineering studies for the needed modifications can be completed. It is estimated that total downtime required to complete the modifications is 2 months per unit.

6.1.3.2 Environmental Performance. Through the application of the combustion modifications described above, it is estimated that emissions of CDD/CDF are reduced to 1,000 ng/dscm, corrected to 7 percent O_2. In addition, CO emissions are reduced to 150 ppmv on a 4-hour average. No change in particulate or acid gas emissions can be expected due to the modifications.

6.1.3.3 Costs. Table 6.1-3 presents the costs required to complete the required combustion modifications. Total capital cost estimates are $4,330,000 for both units. Annualized capital and downtime is estimated to be $1,430,000 based on a 10 percent interest rate and a 15-year facility life. Annual costs are presented in Table 6.1-4. The total annualized costs, which include O&M and annualized capital, are estimated to be $1,690,000.

6.1.4 Best Particulate Control

6.1.4.1 Description of Modifications. The ESP's for this model plant reduce PM emissions from an inlet PM loading of 4.0 gr/dscf to 0.01 gr/dscf at 600^{0}F. Because the flue gas flow rate is reduced after combustion modification, the existing ESP's are assumed to still achieve 0.01 gr/dscf. This outlet PM emission level is the same level required for best PM control (0.01 gr/dscf) and thus is well below the level required for good PM control (0.05 gr/dscf). Therefore, no equipment modifications are required for compliance with either control level.

To cool the flue gas from 600 to 450^{0}F, the flue gas ducting between the economizer and the ESP will be rerouted to the air preheater such that the

TABLE 6.1-3. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 1,000 tpd RDF each)

Item		Costs ($1,000)
DIRECT COSTS:		
Flow Modeling Studies		75
Overfire Air Nozzles		383
Metered Feeders		1,740
Combustion Controller		290
Automatic CO Monitors		44
Ducting, Dampers, Insulation for Air Preheater		352
	Total	2,880
INDIRECT COSTS AND CONTINGENCY:		1,440
TOTAL CAPITAL COSTS		4,330
DOWNTIME COSTS		6,520
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		1,430

TABLE 6.1-4. PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 1,000 tpd RDF each)

Item		Costs ($1,000)
DIRECT COSTS:		
Maintenance Labor		28
Maintenance Materials		28
	Total	56
INDIRECT COSTS:		
Overhead		34
Taxes, Insurance, and Administration		173
Capital Recovery and Downtime		1,430
	Total	1,640
TOTAL ANNUALIZED COST		1,690

flue gas leaving the economizer is sent to the air preheater before going to the ESP. The flue gas temperature at the outlet of the air preheater will be reduced to 450°F from the heat absorbed by the incoming combustion air. As shown in Figure 6.1-4, no relocation of the ID fan is required for modifying the air preheater. The existing opacity monitor can also be used.

Cooling of the flue gas to 450°F will increase the SCA from 520 to 606 ft^2/1,000 acfm, which is sufficient to maintain best PM control. No additional plate area is required to achieve a PM emission level of 0.01 gr/dscf, after the flue gas is cooled to 450°F.

6.1.4.2 Environmental Performance. PM emissions are assumed to be the same before and after cooling of the flue gas. Emissions of CDD/CDF and acid gases are equal to concentrations at the combustor exit.

6.1.4.3 Costs. No additional costs are required for this control option, because the existing ESP can achieve the best particulate control level without incurring additional costs.

6.1.5 Good Acid Gas Control

6.1.5.1 Description of Modification. For good acid gas and CDD/CDF control, dry sorbent will be injected into the combustor through existing overfire air ports. Duct sorbent injection was not considered because of limited space between the economizer and the ESP. New equipment for sorbent injection includes 2 storage silos (1 for each combustor), a pneumatic sorbent transport system, 4 sorbent feed bins (2 for each combustor), and 4 pneumatic sorbent injection nozzles (2 for each combustor). Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full load, a sorbent injection rate of 1,610 lb/hr is required for each combustor with and without good combustion practices. Reduction in HCl and SO_2 are estimated at 80 and 40 percent, respectively.

The air preheater will be modified as discussed in Section 6.1.3.1 to provide flue gas cooling to 350°F. The existing ESP will be reused and be operated at 350°F. The SCA of 680 ft^2/1,000 acfm at 350°F for the existing ESP is more than adequate for removing the injected sorbent during baseline and good combustion conditions. Therefore, the existing ESP will not require additional plate area to reduce PM emissions to 0.01 gr/dscf.

The project also includes monitoring equipment for HCl, SO_2, and O_2. The monitors will be located at the outlet of the existing ESP. Installation

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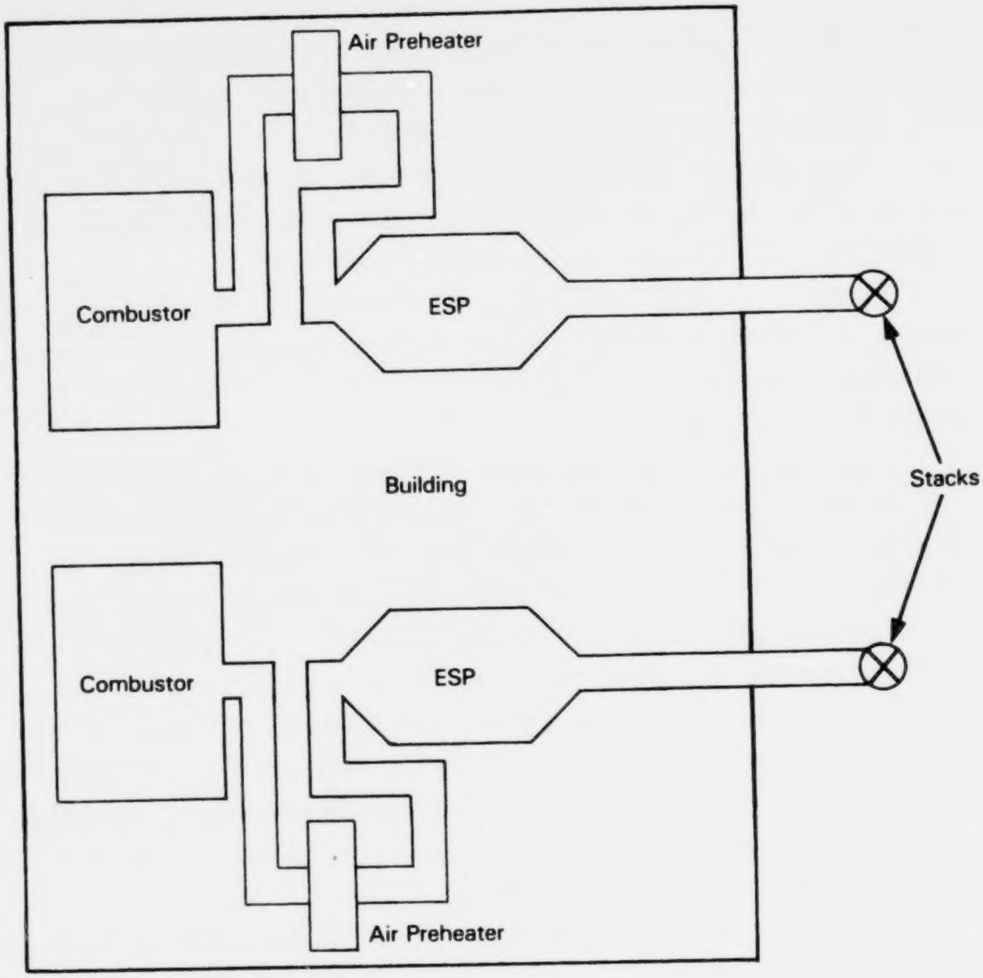

Figure 6.1-4. Plot plan of temperature control equipment arrangement.

of the dry sorbent injection equipment will not require relocation of the ID fan. Figure 6.1-5 shows the retrofit changes. Downtime is expected to be 3 months per combustor.

6.1.5.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced by 92 percent. Acid gas emission reductions are estimated at 50 percent for HCl and 50 percent for SO_2, respectively. As noted above, PM emissions would be 0.01 gr/dscf. An additional 16,400 tons/year of waste (sorbent) will be added to the baseline waste disposal requirements for the plant.

6.1.5.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 6.1-5 for baseline and good combustion practices. Total capital costs are $2,770,00 and $2,240,000 for baseline and good combustion, respectively. Included in the total capital costs for baseline combustion is the costs to modify the air preheater for temperature control. This cost estimate assumes a 10 percent increase in sorbent injection equipment costs.

Annual O&M and indirect costs for both combustion practices are presented in Table 6.1-6. Major direct operating costs are associated with lime and solid waste disposal. The largest annualized cost is capital recovery and downtime. The total annualized costs for the baseline and good combustion are $3,600,000 and $3,510,000, respectively.

6.1.6 Best Acid Gas Control

6.1.6.1 Description of Modifications. To achieve greater reductions of CDD/CDF, SO_2, and HCl, a new spray dryer/fabric filter system will be installed on each combustor. The spray dryer/fabric filter will be located outside the building near the stack. Flue gas from the combustor will be bypassed around the existing ESP and sent to the air preheater before going to the spray dryer and fabric filter. The air preheater will be used to cool the flue gas to $450^{\circ}F$ as discussed in Section 6.1.3.1 as well as provide preheated combustion air to the boilers. The existing ESP will not be demolished. A total of 200 feet of new duct will be installed for connecting the spray dryer and fabric filter to the stack.

Lime slurry will be introduced in each spray dryer at a 2.5:1 calcium-to-acid gas molar ratio. Water rates in the lime slurry of 109 and

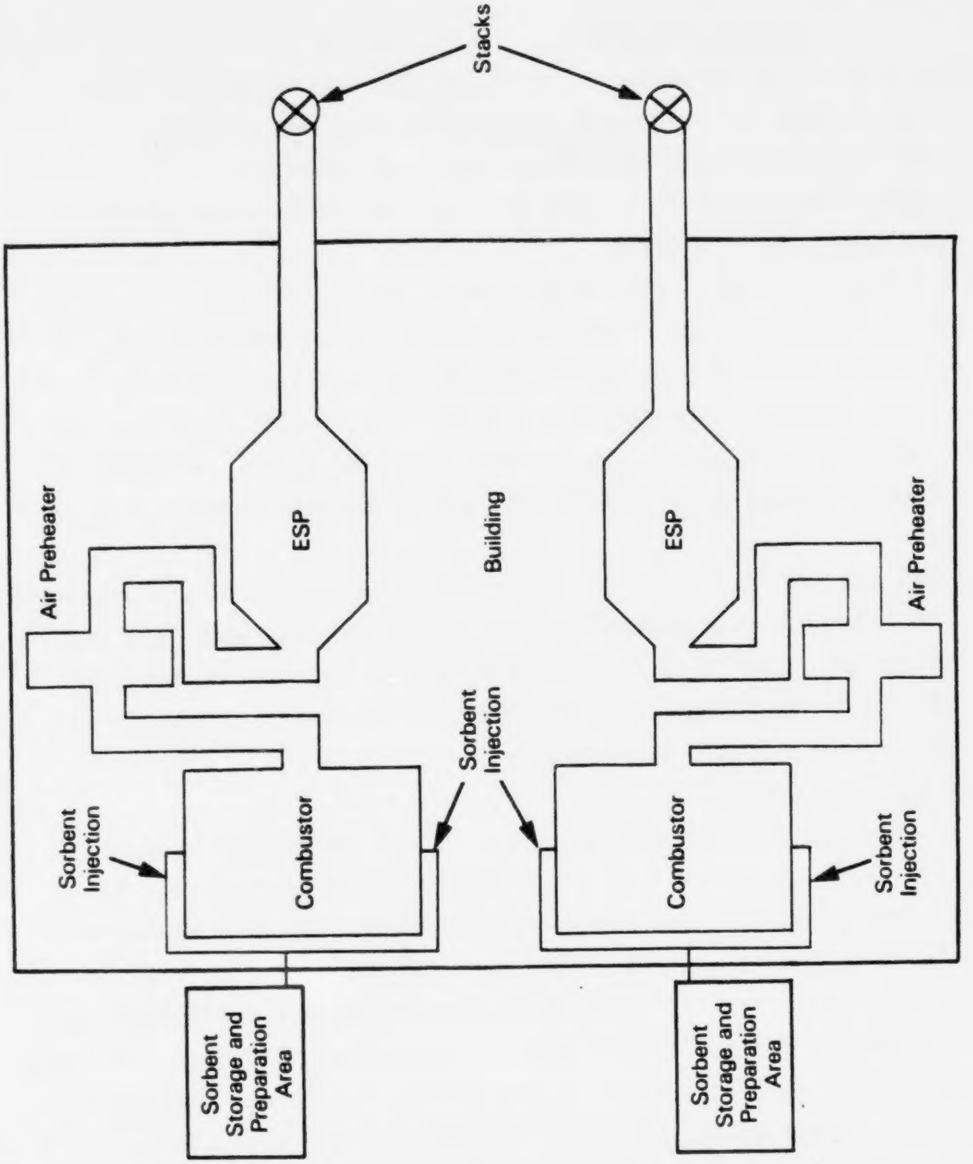

Figure 6.1-5. Plot plan of dry sorbent injection retrofit equipment arrangement.

TABLE 6.1-5. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 1,000 tpd RDF each)

Item	Costs ($1,000) Baseline Combustion Practices	Costs ($1,000) Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control		
Equipment	788	788
Access/Congestion Cost	78	78
Particulate and Temperature Control		
Equipment	0	0
Access/Congestion Cost	0	0
New Flue Gas Ducting		
Ducting Cost	0	0
Access/Congestion Cost	0	0
Other Equipment		
Stacks	0	0
Air Preheater Modifications	352	0[b]
Total	1,220	866
Indirect Costs & Contingencies	1,040	862
Monitoring Equipment[a,b]	514	514
TOTAL CAPITAL COST	2,770	2,240
DOWNTIME COSTS	9,780	9,780
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	1,650	1,580

[a] Turnkey.

[b] Cost for air preheater modifications are included in combustion modification costs (see Table 6.1-3).

TABLE 6.1-6. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 1,000 tpd RDF each)

	Costs ($1,000)	
Item	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Operating Labor	48	48
Supervision	14	14
Maintenance Labor	13	13
Maintenance Materials	43	43
Electricity	28	28
Water	0	0
Lime	1,030	1,030
Waste Disposal	411	411
Monitors	206	206
Total	1,790	1,790
INDIRECT COSTS:		
Overhead	71	71
Taxes, Insurance, and Administration	90	69
Capital Recovery and Downtime	1,650	1,580
Total	1,810	1,720
TOTAL ANNUALIZED COST	3,600	3,510

87 gpm will be required to cool the flue gas to 300°F for each combustor during baseline and good combustion practices, respectively.

The location of the lime receiving, storage, and slurry area which will serve the spray dryers is near the spray dryer. A fabric filter with 73,900 and 60,400 effective square feet of cloth (net air-to-cloth ratio of 4:1) will be installed following each spray dryer during baseline and good combustion, respectively. The increased pressure drop of a fabric filter over an ESP will require a new ID fan for each unit as well. New monitoring instruments for HCl, SO_2, and, O_2 will be installed at both the inlet to the spray dryer and the outlet of the fabric filter. Also, an opacity monitor will be installed at the outlet of the fabric filter. The proposed equipment layout is shown in Figure 6.1-6. Downtime is expected to be 6 months.

6.1.6.2 Environmental Performance. CDD/CDF emissions are expected to decrease to 20 ng/dscm without combustion modifications and 10 ng/dscm with combustion modifications. Emissions of PM will be at 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl. Solid waste will be increased relative to baseline amounts by 7,280 tons per year per combustor or 14,600 tons per year for the plant.

6.1.6.3 Costs. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 6.1-7 for both combustion practices. Total capital costs are estimated at $33,600,000 and $29,700,000 for baseline and good combustion, respectively and include purchase equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume high access and congestion, 200 feet of new ductwork, and new ID fans.

Annual costs are presented in Table 6.1-8 for both combustion conditions. Significant direct operating expenses include maintenance materials and electricity for the larger ID fan needed due to increased pressure drop access in the fabric filter. Total annualized costs are $11,900,000 and $11,000,000 for baseline and good combustion, respectively.

6.1.7 Summary of Control Options

6.1.7.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit

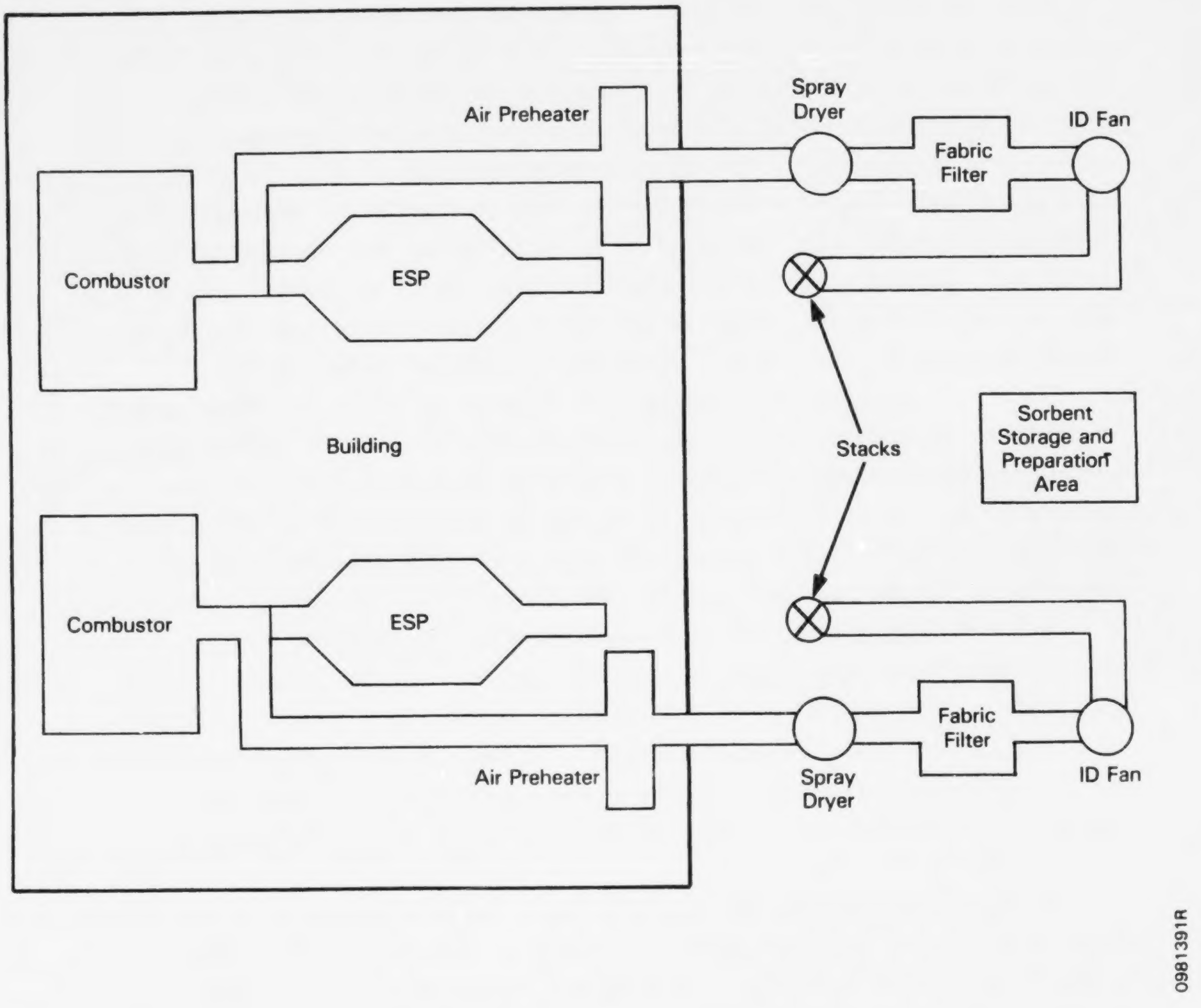

Figure 6.1-6. Plot plan of spray dryer/fabric filter retrofit equipment arrangement.

TABLE 6.1-7. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 1,000 tpd RDF each)

	Costs ($1,000)	
Item	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment	13,000	11,700
Access/Congestion Cost	5,470	4,980
New Flue Gas Ducting[a]		
Ducting Cost	360	326
Access/Congestion Cost	151	136
Other Equipment		
Fans	1,340	1,100
Stacks	0	0
Air Preheater Modifications	352	0[c]
Total	20,700	18,200
Indirect Costs	6,820	6,020
Contingency	5,480	4,850
Monitoring Equipment[b]	573	573
TOTAL CAPITAL COSTS	33,600	29,700
DOWNTIME COSTS	19,600	19,600
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	6,990	6,480

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[a] Based on high access/congestion.

[b] Turnkey.

[c] Costs for air preheater modifications are included in the combustor modification costs (see Table 6.1-3).

TABLE 6.1-8. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Two units of 1,000 tpd RDF each)

Item	Costs ($1,000) Baseline Combustion Practices	Costs ($1,000) Good Combustion Practices
DIRECT COSTS:		
Operating Labor	96	96
Supervision	14	14
Maintenance Labor	53	53
Maintenance Materials	599[a]	522[b]
Electricity	746	611
Compressed Air	109	89
Water	26	21
Lime	853	852
Waste Disposal	548	547
Monitors	215	215
Total	3,260	3,020
INDIRECT COSTS		
Overhead	342	317
Taxes, Insurance, and Administration	1,320	1,160
Capital Recovery and Downtime	6,990	6,480
Total	8,650	7,960
TOTAL ANNUALIZED COSTS	11,900	11,000

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[a] Includes bag replacement costs of $192,000.

[b] Includes bag replacement costs of $157,000.

emission control options. Table 6.1-9 summarizes the combustion, particulate control, and acid gas control technologies described in Sections 6.1.3 through 6.1.6 that were combined for each of the control options described in Section 3.0. It should be noted that since the model plant already achieves good PM control at baseline, Options 1, 2, and 3 are identical.

6.1.7.2 Environmental Performance. The performance of each control option is summarized in Table 6.1-10. For each pollutant, the table presents both the pollutant concentrations and annual emissions. The greatest reductions in acid gases, particulate matter, and CDD/CDF all are arrived with the spray dryer/fabric filter system. The next most effective control for all these pollutants is the dry sorbent injection. Both sorbent addition technologies increases the baseline solid waste disposal between 15 and 17 percent. Combustion modifications reduced baseline CO emissions by 25 percent.

6.1.7.3 Costs. The total annualized cost of each option is presented in Table 6.1-11. The most expensive control option (Option 6 on an annualized cost basis) is the spray dryer/fabric filter installation at $11,800,000. This cost is roughly a factor of 7 higher than the costs for Option 1. Annualized costs for Option 6 are higher than these after Option 7, because the cost associated with the increase in the flue gas flow rate for Option 6 be higher than the increase in cost of Option 7 due to combustion modification. Overall, both capital and annualized costs are higher for higher levels of control.

6.1.7.5 Energy Impacts. Table 6.1-12 presents a summary of the energy impacts associated with the control options. The energy use figures are incremental use. The spray dryer with fabric filter options consume the most electricity. The electricity consumed by Options 6 and 7 is 10,600 and 7,710 MWh/yr, respectively. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and burn the same amount of fuel under baseline and the other control options.

TABLE 6.1-9. SUMMARY OF CONTROL OPTIONS FOR LARGE RDF-FIRED MWC MODEL PLANT

Control Option Description	Combustion Modifications	Temperature Control	Particulate control		Acid Gas Control		
			Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion Control	X	X					
3. Best PM Control and Combustion and Temperature Control	X	X					
4. Good Acid Gas Control, Best PM Control and Temperature Control		X				X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X				X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X			X		X

TABLE 6.1-10. ENVIRONMENTAL PERFORMANCE SUMMARY FOR LARGE RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a,b] (Two units of 1,000 tpd RDF each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	3,000	1,000	1,000	1,000	500	250	20	10
Mg/yr[b]	9.6E-3	3.2E-3	3.2E-3	3.2E-3	1.6E-3	8.0E-4	6.4E-5	1.6E-5
% Reduction vs. Baseline	--	67	67	67	83	92	99.3	99.7
CO Emissions								
(ppmv)	200	150	150	150	200	150	200	150
Mg/yr	739	554	554	554	739	554	739	554
% Reduction vs. Baseline	--	25	25	25	0	25	0	25
PM Emissions								
(gr/dscf)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	73	73	73	73	73	73	73	73
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
SO_2 Emissions								
(ppmv)	300	300	300	300	150	150	29	29
Mg/yr	2,420	2,420	2,420	2,420	1,210	1,210	230	230
% Reduction vs. Baseline	--	0	0	0	50	50	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	250	250	15	15
Mg/yr	2,430	2,430	2,430	2,430	1,215	1,215	73	73
% Reduction vs. Baseline	--	0	0	0	50	50	97	97
Total Solid Waste								
(tons/day)	200	200	200	200	249	249	265	265
Mg/yr	60,500	60,500	60,500	60,500	75,400	75,400	80,400	80,400
% Increase vs. Baseline	--	0	0	0	25	25	33	33

[a] All flue gas concentrations are reported on a 7 percent O_2 dry basis.

[b] Mass emission rates are for total plant (both combustors).

TABLE 6.1-11. COST SUMMARY FOR LARGE RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units of 1,000 tpd RDF each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	4,330	4,330	4,330	2,770	6,570	33,600	34,000
Downtime Cost	6,520	6,520	6,520	9,780	9,780	19,600	19,600
Annualized Capital and Downtime Cost	1,430	1,430	1,430	1,650	2,150	6,990	7,050
Direct O&M Cost	56	56	56	1,790	1,850	3,260	3,080
Total Annual Cost	1,690	1,690	1,690	3,600	4,340	11,900	11,800
Cost Effectiveness ($/ton RDF)	2.53	2.53	2.53	5.40	6.51	17.90	17.70
Facility Downtime (Months)	2	2	2	3	3	6	6
Total Compliance Time (Months)	7	7	7	19	19	25	25

[a] All costs (except cost effectiveness) in $1000. All costs given in December 1987 dollars.

TABLE 6.1-12. PLANT TOTAL ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	0	0
4	615	0
5	615	0
6	16,200[b]	0
7	13,300[b]	0

[a] Increase from baseline consumption.

[b] Total electrical use excludes the electrical savings of not operating the existing ESP's.

6.2 SMALL RDF-FIRED COMBUSTOR

This section presents case study results for small RDF-fired MWC facilities (individual unit size less than 600 tpd). As shown in Table 6.0-1, 8 existing facilities are represented by this subcategory. Section 6.2.1 presents a description of the Albany, NY facility, which was visited to gather information for model development. Section 6.2.2 presents a description of the model plant, including baseline design and performance assumptions. Section 6.2.3 to 6.2.6 detail the retrofit requirements, estimated performance, and costs associated with each retrofit option. Section 6.2.7 presents a summary of the control options, which are discussed in more detail in Section 3.0 of this report.

6.2.1 Description of the Albany, NY RDF-Fired Facility[4]

The Albany New York Solid Waste Energy Recovery System (ANSWERS) consists of 2 component plants:

- RDF production plant owned the City of Albany and operated under contract by AENCO, and
- Sheridan Avenue steam plant designed, owned, and operated by New York Office of General Services.

The RDF processing plant is remotely located from the steam plant, because of space limitations at the steam plant. The steam plant is situated on less than an acre of land so that limited space is available for delivery and storage.

The Albany Sheridan Avenue RDF-fired plant began operation in 1981. It consists of 2 identical waterwall combustors (boiler and firing system) supplied by Zurn. Each combustor has a rated capacity of 300 tpd RDF (total plant capacity 600 tpd). Plant design data are shown in Table 6.2-1. Normal firing rate was reported to be about 500 tpd. The lower firing rate is the result of limited steam demands and boiler/stoker size limitations which will be discussed below. Maximum operating capacity was reported to be about 640 to 660 tpd. Steam is produced for district heating and cooling for the downtime Albany (Empire State Plaza) area. Steam generating capacities are 100,000 lb/hr of 250 psig steam at 450°F. The plant operates 7 days/week and 24 hours/day.

TABLE 6.2-1. ALBANY DESIGN DATA

Combustor:	
Type	- Straight Wall Spreader-Stoker
Number of Combustors	- 2
Combustor Unit Capacity	- 300 tpd
Plant Capacity	- 600 tpd
Emission Controls:	
Type	- Electrostatic Precipitator
Number of Precipitators	- 2 (one per combustor)
Manufacturer	- Precipitair
Number of Fields	- 3
Inlet design particulate loading	- 3.0 gr/dscf at 12% CO_2
Operating Temperature	- [illegible]00 to 450°F
Design Collection Efficiency	- 99 percent
Controlled PM Emissions	- 0.03 gr/dscf at 12% CO_2
Gas Flow	- 134,000 acfm

6.2.1.1 Combustor Design and Operation. The City collects MSW and processes RDF that is sold to the steam plant based on the current price of oil. According to the contract with the State, the City of Albany is paid 63.3 percent of the cost of oil required to produce the same quantity of steam as is actually produced by firing RDF. The heating value of RDF was measured in tests performed by Raltech Laboratories in St. Louis in 1980, and was reported to be between 4,500 and 4,600 Btu/lb.

The RDF produced at Albany is a coarse fluff RDF. The front-end processing consists of two 1,500 hp diesel powered shear shredders with 50 tons/hour capacity (each) and magnetic separators. The typical particle size distribution of the RDF is 96.5 percent of the particles less than 2 by 2 inches. Trucks deliver the RDF to the steam generating plant and dump it into a storage pit. An overhead crane transfers RDF from the dumping station to a live center surge bin, where it is metered into separate chutes that feed the combustors. The surge bin contains 8 vertical and 2 horizontal metering screws. There are 2 air-swept RDF distributors per combustor. A deflection plate in the distributor controls the trajectory of the fuel and attempts to spread the RDF evenly from front to rear on the grate. Plant personnel estimate that 40 to 50 percent of the RDF burns in suspension.

Both of the combustion trains are identical. Typical of suspension-fired RDF systems, a single traveling grate moves from the rear to the front of each combustor at a fixed speed. Television cameras view across the discharge end of the grate to allow observation of fuel burnout. If burning is occurring at the end of the grate, the rate of fuel feeding is reduced. The length of the traveling grate is approximately 19 feet. Based on burnout of waste on the grate, the plant manager estimates that the grate is approximately 30 percent too short. The single-speed stoker could accommodate burn out at design load if the grate was longer or if the speed could be reduced. Currently, however, the firing rates cannot be increased to achieve the design load. A profile of the boiler and gas cleaning equipment is provided in Figure 6.2-1.

Underfire air is supplied through a single plenum beneath the grate. Each boiler includes 2 rows of overfire air nozzles on the boiler front wall and 2 rows of nozzles on the rear wall. On the front wall, 1 row of nozzles

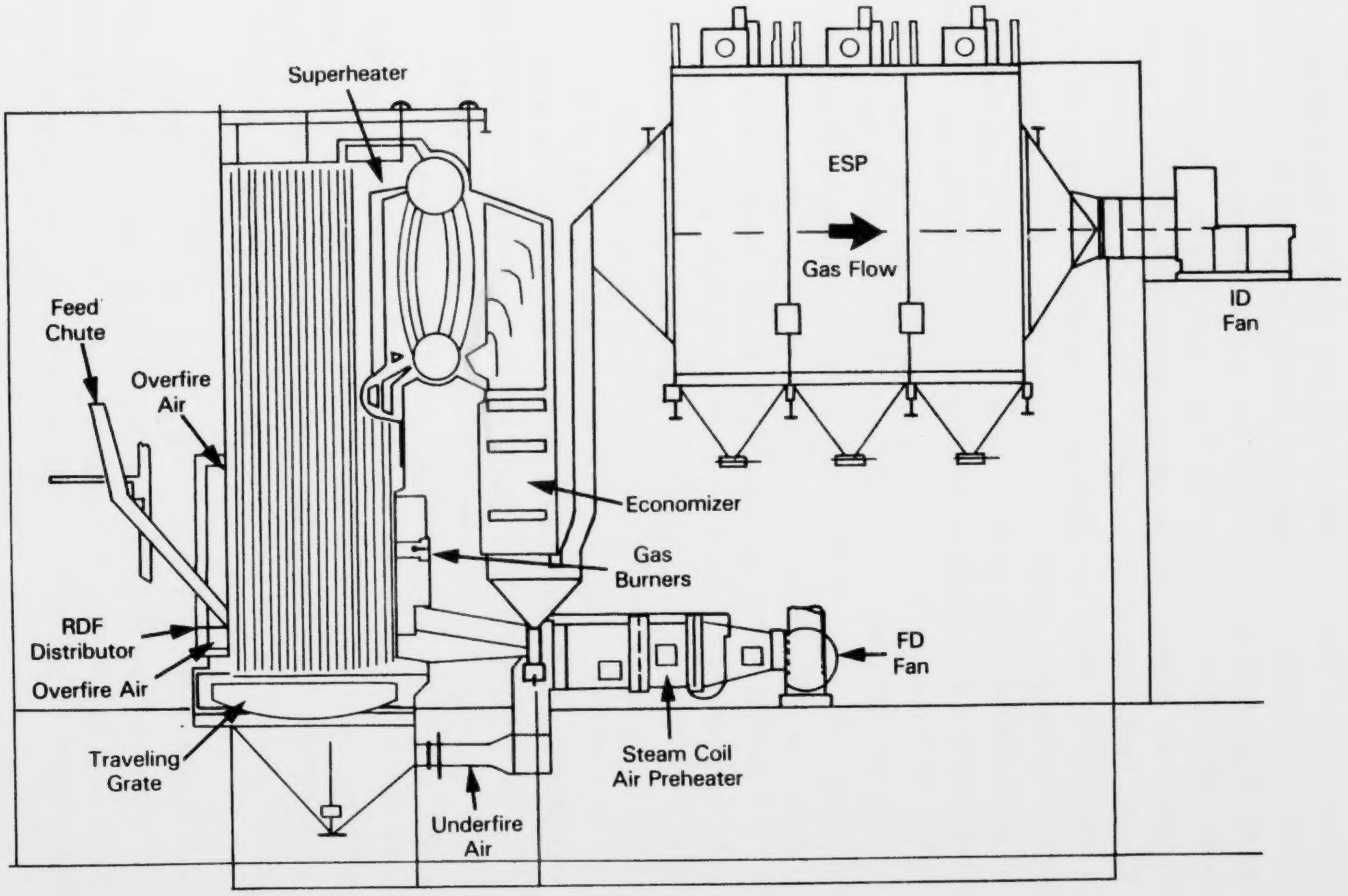

Figure 6.2-1. Albany RDF-fired boiler.

is located about 3 feet above the RDF distributor and the other is approximately 25 feet above the distributor. On the rear wall, 1 row is located at the level of the distributors and the other is approximately 20 feet above the distributor. The operating permit specifies that the system be operated at 50 percent excess air, but the actual operating rate is between 80 and 100 percent excess air with no overfire air. The actual excess air levels are higher than design to improve boiler stability and to minimize CO emissions. Operating instability reportedly results at 50 percent excess air. Plans are underway to remove the overfire air from both combustors in the near future. This decision was based on results from a number of tests including PM emission levels and continuous gas monitoring under varying overfire air operating conditions. The Plant Manager stated that the lowest CO levels were achieved when overfire air was off.

The boilers are equipped with auxiliary fuel burners which can fire fuel oil or natural gas. Gas is preferred over oil, because problems with sidewall erosion have been encountered when oil is fired. The auxiliary fuel burners are located on the lower rear wall of the boilers about 5 feet above the RDF distributors. Each unit contains 3 burners with a combined heat output of 85 percent of load capacity (approximately 106 MM Btu/hr). The burners are fired during start-up to achieve steam pressure and temperature. Approximately 4 hours of gas firing are required prior to bringing the ESP's on line. Auxiliary fuel is normally fired for 8 to 9 hours before RDF feeding begins. One boiler is brought off line each week from midnight on Friday until midnight on Saturday. The plant reports that there have been only 2 unscheduled outages in 7 years of operation.

Since the RDF distributors are located on the opposite wall from the auxiliary burners, problems with the RDF plugging the ignition and air doors have been encountered. The steam plant is considering changing the location of the auxiliary burners to the front wall of the combustor at a different elevation.

Combustor temperatures were originally measured by 1 thermocouple located just below the nose in the rear waterwall. Because of the extreme temperatures at this location, the thermocouple had a short life. The plant plans to replace this thermocouple with 3 thermocouples. The 3 thermocouples are to be located in a row on the back wall higher up in the combustor. The recorded temperature will be an average of the 3 thermocouple values.

A number of additional design features are being altered in each of the combustors. For example, the underfire air was originally preheated by a steam-coil preheater, but this practice has been stopped. Stack gas temperatures have hence been reduced from 500^{0}F to 450^{0}F. The lower 7 feet of the furnaces were originally lined with silicon carbide refractory, but this has been removed due to excessive build up of slag on the walls which required removal by spikes and sledge hammers. Another factor contributing to slagging was the practice of reinjecting economizer fly ash into the furnace. This material was being injected through 3/4-inch tubes approximately 36 inches above the grate, and it was migrating to the side wall and slagging. The injection also caused a sandblasting effect on the waterwall tubes. In an effort to minimize these erosion problems this practice was discontinued.

Continuous gas monitoring for CO and O_2 takes place at the boiler exit. Boiler controls include air flows which are automatically adjusted based on steam flow. As mentioned above, the stoker is a single-speed type. RDF feeding can be adjusted automatically based on steam flow and temperature or varied manually by adjusting the surge bin horizontal screw speeds. The plant attempts to keep minimum boiler loads at 70 percent of rated capacity; boiler stability becomes a problem when load is reduced to between 50 and 60 percent. Burn out is acceptable based on visual inspections of the ash. There are 6 combination gas/oil fired boilers adjacent to the RDF units to pick up load swings as necessary when the waste-fired combustors are down for scheduled maintenance. These boilers also can be operated during low steam demands.

6.2.1.2 Emission Control System Design and Operation. Emissions are controlled by two 3-field ESP's. Table 6.2-1 presents the design data for the ESP's built by Precipitair and in use since the plant began operation. The ESP's are located inside of the building. No major rebuilds have ever been performed on them. Little detailed information about the ESP's was available from the Plant Manager at the time of the visit.

The ESP's typically operate with an inlet temperature of about 400 to 450°F. Operating parameters recorded during the visit included:

Primary Voltage - 150 to 200 Volts AC
Primary Current - 1 to 20 Amps AC
Precipitator Voltage - 30 kV

The permit PM emission limit for the plant is 0.03 gr/dscf corrected to 12 percent CO_2. Measured PM emissions ranged widely from 0.02 to 0.34 gr/dscf corrected to 70 percent O_2. Continuous opacity, SO_2, and NO_x monitors are located in the stack. A single stack serves both boilers. Emissions data available from 1 test in which RDF was the only fuel had HCl and SO_2 emissions at the stack of 50 and 225 ppm, corrected to 7 percent O_2. CDD/CDF emissions during a single test series were 578 ng/Nm^3 corrected to 12 percent CO_2. During the visit, stack opacity was observed to be 9 to 11 percent, as measured by the opacity monitor.

Fly ash and bottom ash are currently combined for co-disposal in a landfill. There were numerous problems with the original ash handling equipment which have resulted in a redesign of this portion of the plant. Fly ash is currently conveyed to a separate truck loading area. The newly designed ash handling system will start up sometime in the summer of 1988. Total ash is estimated to be between 23 and 28 percent by weight of the incoming RDF.

6.2.2 Description of Model Plant

There are 9 facilities firing RDF in small spreader-stoker boilers (unit size less than 600 tpd). The oldest facilities in the group began operating in 1979. Five of the 9 facilities have begun full-scale operation in the last year: Red Wing, MN and Mankato, MN are converted coal-fired stoker units; Biddeford, ME and Penobscot, ME co-fire wood with RDF; and Portsmouth, VA co-fires RDF and coal. The Columbus facility commenced operation in 1983, co-firing RDF and coal in its 6 boilers. Current practice is to fire the fuels separately, using coal only as needed during RDF shortages or during peak steam demands. The following sections describe the model plant developed to represent the facilities in this category.

6.2.2.1 Combustor Design and Operation. Table 6.2-2 presents design data for the model plant. The model plant configuration consists of two

TABLE 6.2-2 MODEL PLANT BASELINE DATA FOR SMALL RDF-FIRED COMBUSTOR

Combustor:	
Type	Straight Wall Spreader-Stoker
Number of Combustors	2
Combustor Unit Capacity	300 tpd
Plant Capacity	600 tpd
Excess Air	80 percent
Emission Controls:	
Type	Electrostatic Precipitator
Number of Precipitators	2, one per combustor
Number of Fields	4 each
Inlet Temperature	450°F
Collection Efficiency	99.8 percent
Gas Flow	82,800 acfm
Total Plate Area	39,600 ft^2
SCA at 82,800 acfm and 450°F	478
Emissions:[a]	
CDD/CDF (tetra - octa)	2000 ng/dscm
PM (stack)	0.01 gr/dscf[b]
CO	200 ppmv
HCl	500 ppmv
SO_2	300 ppmv
Stack Parameters:	
Height	200 feet
Diameter	8 feet
Operating Data:	
Remaining Plant Life	$\geq$ 20 years
Annual Operating Hours	8,000 hours
Annual Operating Cost	$12,200,000

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[a] All emissions are dry, corrected to 7 percent O_2. Standard and Normal conditions are both 1 atmosphere and 70°F.

[b] Inlet PM emissions to the ESP are 4.0 gr/dscf at 7 percent O_2.

300-tpd boilers, each firing 100 percent RDF. Five of the 9 existing plants consist of 2 individual boilers; there are 3, 4, and 6 boilers at Akron, Portsmouth and Columbus, respectively. Unit sizes vary from 60 to 400 tpd, with the exception of the 500 tpd boilers at Portsmouth. With the exception of the newer Biddeford boiler, which uses a pinched-wall lower furnace design, all of the boilers in the population are straight-wall designs. Therefore, the model plant configuration includes 2 straight-wall boilers. All of the facilities utilize a traveling grate with a single underfire air plenum. This design feature is also included in the model plant. Typical of all existing facilities, fuel feeding is accomplished by air-swept distributors. The number of distributors varies with unit capacity. For example, the 300 tpd boilers at Albany include 2 distributors per unit, and the 1,000 tpd boilers at Niagara Falls have 8 distributors each. Each of the 300 tpd units in the model plant is assumed to have 2 individual distributors located on the boiler front wall.

Underfire air and overfire air are generally preheated prior to injection into the combustion chamber. Based on an assessment of available information from existing facilities included in this category, it is assumed that a tubular air heater is used, and that it is located upstream of the flue gas cleaning equipment. Underfire and overfire air temperatures are assumed to be 350°F entering the furnace, and flue gas temperatures exiting the air heater are 450°F. The boiler is assumed to operate at 80 percent excess air, with 70 percent of the total air supplied as underfire air. The remaining 30 percent is supplied as overfire air. At 80 percent excess air, total combustion air requirements are 42,500 scfm, with 29,750 scfm as underfire air. Total gas flow at the preheater is approximately 82,800 acfm.

All RDF boilers have auxiliary fuel firing capacity. This is necessary due to the potential for interruption in RDF feeding. It is assumed that the model boilers have two combination gas/oil burners located on the rear wall above the traveling grate. The burners have the ability to carry 100 percent of the boiler's design steam load. Some of the facilities in this group of plants have in the past injected captured economizer ash back into the combustion chamber of the boiler. This practice has largely been discontinued due to waterwall tube erosion and slagging problems. As a result, this design feature has not been included in the model plant.

The most common combustion control loop in an RDF-fired plant utilizes automatic control of fuel feed rates to maintain desired steam flow or pressures. This feature is included in the control system for the model plant. It is assumed that the combustion air flows and grate speed are adjusted manually in response to temperature and excess oxygen readings in each unit. It is assumed that temperatures are measured in the upper furnace and at the economizer outlet, and that a continuous oxygen monitor is located at the economizer outlet.

6.2.2.2 Emission Control System Design and Operation. As shown in Table 6.0-1, 8 of the 9 plants in this subcategory are equipped with ESP's. The Albany plant has a 3-field ESP on each combustor with PM emissions ranging from 0.02 to 0.34 gr/dscf at 7 percent O_2. Most existing plants are equipped with 4-field ESP's. Therefore, the model plant is equipped with 4-field ESP's controlling PM emissions to 0.01 gr/dscf at 7 percent O_2. Emissions data show that 4-field ESP's are capable of achieving PM emissions of 0.01 gr/dscf for this type of facility.

A tubular air preheater is located upstream of the ESP to provide preheated combustion air while cooling the flue gas to $450^{o}F$. Each combustor is connected to its own stack. Because the combustors, air preheaters, and ESP's are located indoors, a high access and congestion level is assumed for APCD retrofitting. A plot plan of the model plant is shown in Figure 6.2-2.

Total ash is assumed to be 10 percent of the incoming RDF by weight. This value is lower than the 23 to 28 percent observed at Albany, but is considered to be more representative of the RDF population. A considerable amount of metal (wire, etc.) goes through the RDF processing plant at Albany and ends up in the waste feed.

6.2.2.3 Environmental Baseline. Table 6.2-2 presents baseline emission data for the model plant based on an assessment of available measured emissions data. All emission estimates are corrected to 7 percent O_2 at the economizer outlet. Baseline uncontrolled CDD/CDF emissions are 2,000 ng/dscm. Uncontrolled particulate emissions are 4.0 gr/dscf

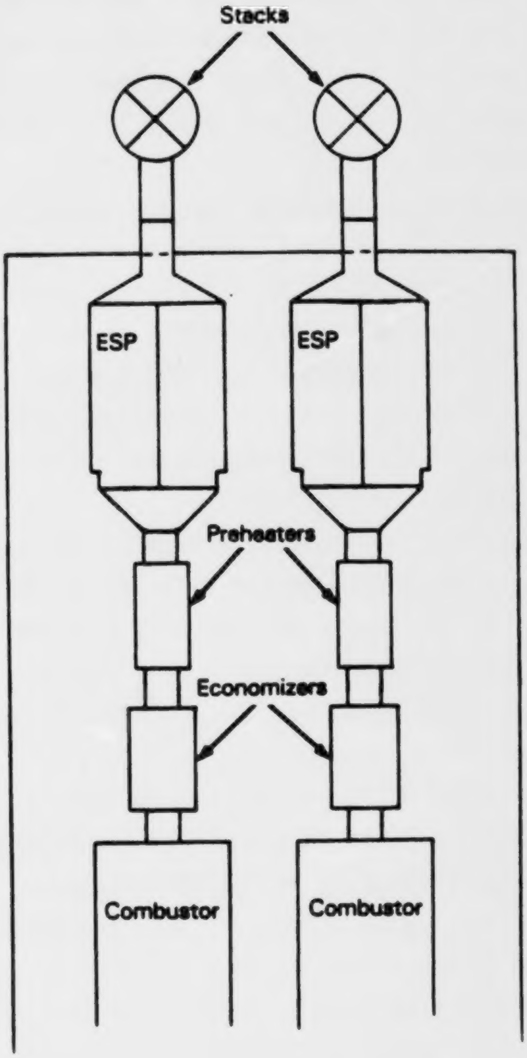

Figure 6.2-2. Plot Plan of Model Plant

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and CO emissions are 200 ppmv. Uncontrolled HCl and SO_2 emissions are assumed to be 500 ppmv and 300 ppmv, respectively.

6.2.3 Good Combustion Control

The following sections describe retrofits necessary to bring the performance of the model plant to a level representing good combustion practice. The retrofits address design, operation control, and verification elements of good combustion practices.

6.2.3.1 Description of Modifications

Overfire Air System. The baseline CDD/CDF and CO emissions indicate that flue gas mixing conditions are not optimized in the system, and that some redesign is necessary. Flow modeling studies can be used to establish the optimum overfire air firing pattern. For this model plant, it is assumed that the new overfire air design includes four rows of overfire air nozzles which are designed to provide 40 percent of the total combustion air. New supply headers are equipped with pressure sensors to verify pressures from which velocities and nozzle penetrations can be calculated.

It is assumed that the existing overfire air fan has sufficient load capacity to supply 40 percent of the total combustion air (17,000 dscfm). Actual overfire air flow rates are assumed to be 30 percent of total air (12,800 dscfm). The radiation sections of the boiler are assumed to be membrane wall construction. It is assumed that the overfire air nozzle sizes and pressures require modification, and that some waterwall tube realignment is required. Lastly, as part of flow modeling, the effects of auxiliary fuel firing on mixing patterns should be examined. Verification of mixing conditions and final adjustment of overfire air nozzle settings can be established by CO profiling studies.

Fuel Feeding. RDF-fired boilers use fuel feed rate as the primary control variable to maintain desired steam flows. It is essential that the feeding system be designed to provide a relatively constant feed rate to the combustor. The distribution of fuel on the traveling grate is also an important operating parameter for maintaining stable combustion conditions. Because the grate is supplied with underfire air from a single plenum, uneven waste distributions and inconsistent bed densities will result in channeling of underfire air through less dense portions of the fuel bed.

This leads to less stable burning conditions and variable lower furnace stoichiometry, with fuel-lean flue gases emitted from some areas of the waste bed and fuel-rich flue gases from other areas. These conditions will lead to potentially higher levels of organic emissions.

This problem can be corrected by installing individual metered feeding modules for each RDF distributor. Each metered feeding module, consisting of two fuel bins, a ram, and a variable speed conveyor, will be installed at the front of each boiler. Normally, installation of this system at a new boiler is accomplished by lifting the equipment into place by crane prior to completing the building roof. Therefore, it is assumed that the model plant will require removal of a portion of the furnace building roof in order to install the metered feeders.

The modification provides a more constant feed rate to the boilers and more uniform distribution of waste on the grates. This will result in stable burning conditions and better control of lower furnace stoichiometry, minimizing the potential for periods of high air emissions.

Air Heater Bypass. A bypass duct and dampers will be installed to allow up to 100 percent of the combustion gases to be bypassed around the air heater. This modification provides the operator with the ability to vary air preheat temperatures as needed to accommodate changes in waste characteristics and boiler operation.

Combustion Control and Monitoring. The existing combustion control system will be modified to include additional operating parameters, and additional flue gas monitors are required for performance verification. As a minimum, the following operating parameters will be incorporated into the existing control scheme:

- steam flow rates
- fuel feed rates
- excess air flows
- CO levels
- flue gas temperatures
- underfire and overfire air flows or pressures
- furnace pressures

It is assumed that steam drum levels and pressures and feedwater flow rates are also included in the control system. A combustion control scheme based on these operating parameters can be established by use of microprocessorbased electronic instrumentation, providing total system control. Manual override functions will be in place so that the operators can start the system up manually, switching to automatic control when stable combustion conditions are established. Continuous CO monitors must be installed with integrators and readouts, so that verification of combustion efficiency can be established. It is sufficient for grate speed adjustments to be made manually based on periodic visual observations of the ash bed coming off the front of the grate.

Retrofit Considerations. Flow modeling studies can be completed in 3 months while the units continue to operate. It is estimated that all remaining modifications can be made with 2 months of downtime per unit.

6.2.3.2 Environmental Performance. As a result of applying the above described combustion modifications to the model plant, it is estimated that CDD/CDF emissions will be reduced to 1,000 ng/dscm, corrected to 7 percent O_2. In addition, a reduction in CO emissions to 150 ppmv can be expected to occur as a result of these modifications. The modifications would also have no effect on solid waste disposal quantities.

6.2.3.3 Costs. The capital costs required to complete the combustion modifications are presented in Table 6.2-3. Total capital costs are estimated to be $2,370,000. Downtime cost is estimated at $1,960,000. Based on a 15-year remaining plant life, and a 10-percent interest rate, the annualized capital and downtime cost is $569,000. Table 6.2-4 presents the annual O&M costs. Annual O&M costs of the modifications are estimated to be $56,000. Total annual costs including O&M and annualized capital and downtime are estimated to be $754,000.

6.2.4 Best Particulate Control

The ESP's in place on this model plant already reduce PM from an inlet loading of 4.0 gr/dscf to an outlet emission rate of 0.01 gr/dscf (values corrected to 7 percent O_2). This emission rate is equal to the rate required for best PM control and is significantly lower than the rate designated as good control. Thus, no modifications of particulate control equipment will be required for compliance at either control level for this model plant.

6.2.5 Good Acid Gas Control

6.2.5.1 Description of Modifications. For good acid gas control, hydrated lime will be injected into each combustor through the overfire air

TABLE 6.2-3. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS
(Two units at 300 tpd each)

Item	Cost ($1,000)
DIRECT COSTS:	
Metered Feeding System	870
Flow Modeling Studies	75
Overfire Air Nozzles	257
Automatic Combustion Control System	290
CO Profiling	10
CO Monitors with Readouts and Integrators	44
Air Heater Bypass Ducting, Damper, Insulation	33
Total	1,580
INDIRECT COSTS AND CONTINGENCY:	790
TOTAL CAPITAL COSTS	2,370
DOWNTIME	1,960
ANNUALIZED CAPITAL COSTS AND DOWNTIME	569

TABLE 6.2-4. PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 300 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Operating Labor		0
Maintenance Labor		28
Maintenance Materials		28
	Total	56
INDIRECT COSTS:		
Overhead		34
Taxes, Insurance, Administrative		95
Capital Recovery and Downtime		569
	Total	698
TOTAL ANNUALIZED COST		754

ports. Hydrated lime sorbent will be fed at 480 lb/hr to each combustor (at full operating rate) for a calcium-to-acid gas molar ratio of 2:1. Additional equipment for sorbent injection will include a storage silo, a pneumatic sorbent transfer system, 4 sorbent feed bins (2 for each combustor) and pneumatic injection nozzles. Duct sorbent injection is not practical because of the limited space between the economizer and the ESP. To cool the flue gas from 450^0F to 350^0F, a spray humidification chamber will be installed on the roof of the building approximately above each economizer. Water spray at 9 gpm will be required for the gas cooling for each combustor. Thirty feet of duct between the preheater and the ESP on each combustor will be removed and replaced with 120 feet of new duct that carries flue gas from the preheater through the spray chamber and then to the ESP.

An additional 4,000 square feet of ESP plate area will be required to collect the injected sorbent. Each new ESP will be erected outside the building next to the stack and will be connected to the existing ESP and the stack with 75 feet of new duct. The proposed equipment arrangement is shown in Figure 6.2-3.

The new ESP's and humidification chambers with associated ducting will add sufficient pressure drop to require replacement of the ID fans. New monitoring equipment for SO_2, HCl, O_2, and CO_2 is also included. Downtime is expected to be 3 months per combustor.

6.2.5.2 Environmental Performance. CDD/CDF emissions are expected to be reduced 88 percent from baseline levels. Acid gas emission reductions are estimated at 50 percent for HCl and 50 percent for SO_2. Particulate matter emissions will remain at 0.01 gr/dscf, but the collected sorbent will add 4,920 tons per year of solid waste to the baseline disposal requirements for the plant.

6.2.5.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 6.2-5. Total capital cost is \$5,660,000. Downtime cost is \$2,390,000. Most of the capital cost is associated with the new equipment for particulate and temperature control. The cost estimates assume a high access/congestion level for new equipment and duct demolition.

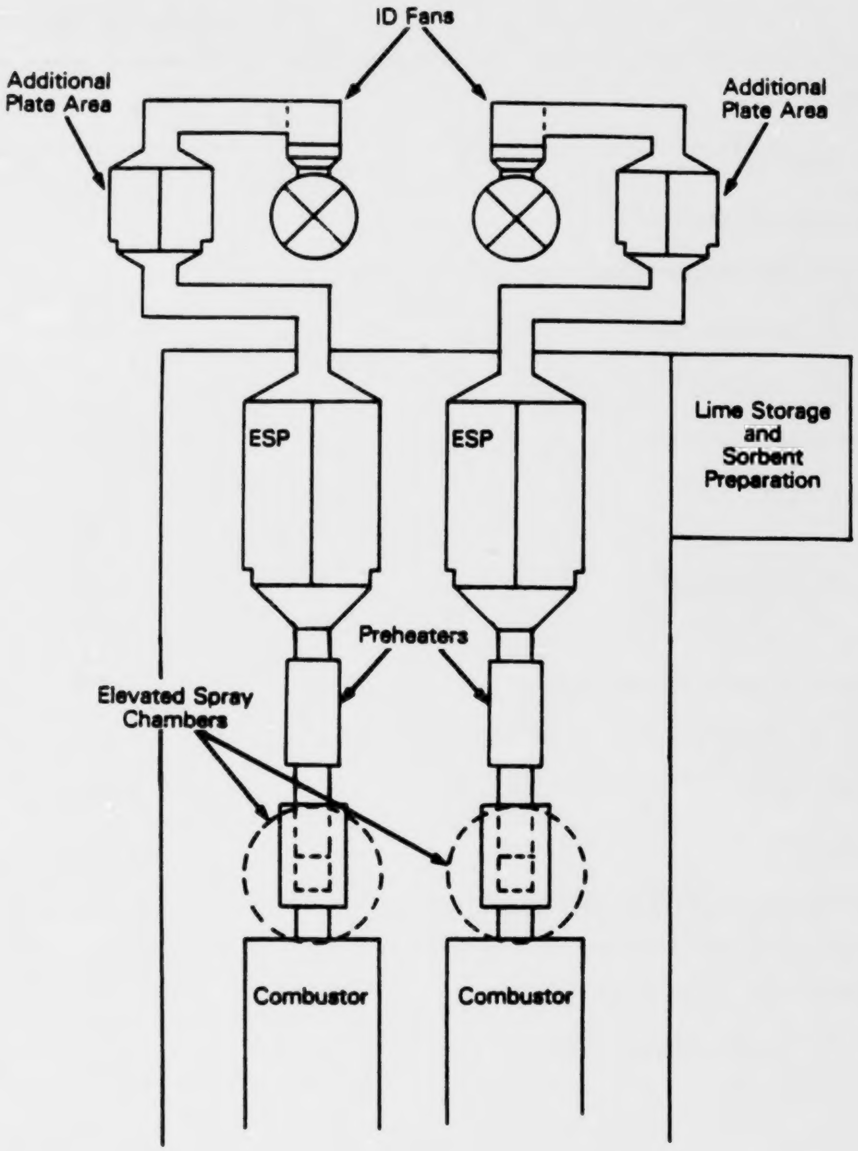

Figure 6.2-3. Plot Plan of Sorbent Injection Equipment Arrangement

TABLE 6.2-5. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 300 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment		672
Access/Congestion Cost		67
Particulate and Temperature Control[b]		
Equipment		1,540
Access/Congestion Cost		645
New Flue Gas Ducting[a]		
Ducting Cost		183
Access/Congestion Cost		77
Other Equipment		
Fans		450
Stacks		0
Demolition/relocation		18
	Total	3,650
Indirect Costs & Contingencies		1,490
Monitoring Equipment[c]		514
TOTAL CAPITAL COST		5,660
DOWNTIME COST		2,930
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		1,130

[a] Based on moderate access/congestion.

[b] Based on high access/congestion.

[c] Turnkey.

Annual costs are presented in Table 6.2-6. The major direct operating and maintenance costs are sorbent purchase and monitoring instrument maintenance. Total annualized cost of dry sorbent injection, including capital recovery and downtime, is $2,270,000.

6.2.6 Best Acid Gas Control

6.2.6.1 Description of Modifications. To achieve greater reductions in CDD/CDF, HCl, and SO_2, a spray dryer/fabric filter system will be installed on each combustor. The new equipment will be located outside the building, near the stacks. The existing ESP's will not be demolished, but the flue gas will be bypassed around each ESP from the preheater to the spray dryer. Approximately 50 feet of duct will be demolished (25 feet at each end of the ESP) to make room for each new ESP bypass duct. A total of 250 feet of new duct per combustor will be required to connect each spray dryer and fabric filter between the preheater and the stack. The proposed equipment configuration is shown in Figure 6.2-4.

Lime slurry will be introduced into each spray dryer at a calcium-to-acid gas molar ratio of 2.5:1. Water in the lime slurry equivalent to 13 gpm is needed to cool the gas stream from $450^{o}F$ to $300^{o}F$.

The lime receiving, storage, and slurry area which will serve the spray dryers is also shown in Figure 6.2-4. The fabric filters will each have 24,200 effective square feet of cloth (net air-to-cloth ratio of 4:1). The increased pressure drop of fabric filters over ESP's will require a new, larger ID fan for each unit. New monitoring equipment for HCl, SO_2, CO_2, O_2 and opacity will be installed as well. Downtime is expected to be 6 months.

6.2.6.2 Environmental Performance. CDD/CDF emission reductions of 99 percent from inlet level or to 10 ng/Nm^3 are expected. Emissions of PM will be maintained at 0.01 gr/dscf. Acid gas emissions will be reduced 90 percent for SO_2 and 97 percent for HCl.

6.2.6.3 Costs. Capital cost requirements for installing spray dryer/fabric filter systems are presented in Table 6.2-7. Total capital costs are estimated at $15,900,000. This figure includes purchased equipment, installation, ductwork demolition, and indirect costs such as engineering and contingencies. Estimates assume high access and congestion,

TABLE 6.2-6. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITION OF ESP PLATE AREA (Two units of 300 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Operating Labor		60
Supervision		16
Maintenance Labor		26
Maintenance Materials		69
Electricity		28
Water		4
Lime		309
Waste Disposal		123
Monitors		206
	Total	841
INDIRECT COSTS:		
Overhead		100
Taxes, Insurance, and Administration		197
Capital Recovery and Downtime		1,130
	Total	1,430
TOTAL ANNUALIZED COST		2,270

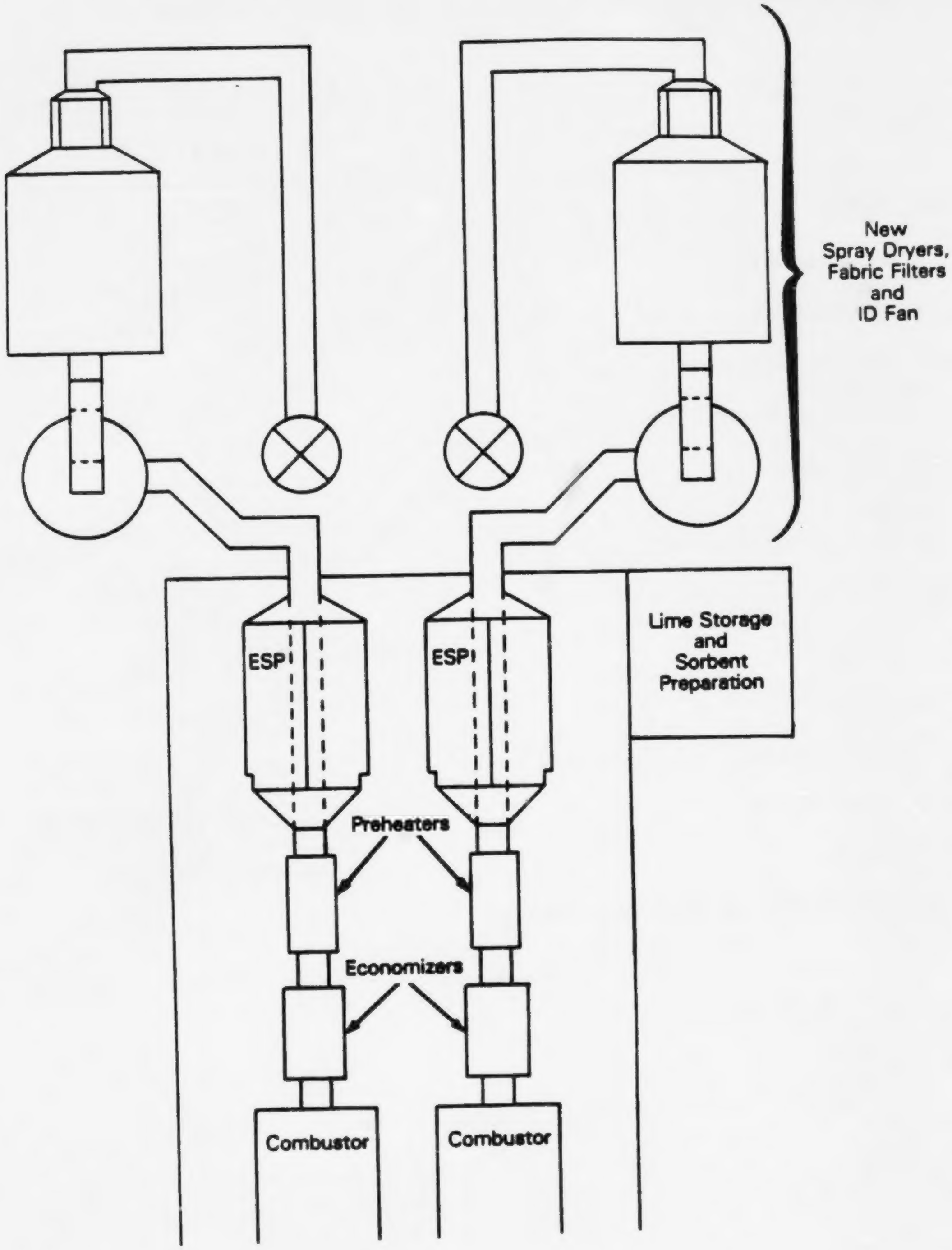

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Figure 6.2-4. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement

TABLE 6.2-7. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 300 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment		6,300
Access/Congestion Cost		2,650
New Flue Gas Ducting[a]		
Ducting Cost		223
Access/Congestion Cost		94
Other Equipment		
Fans		347
Stacks		0
Demolition/Relocation		23
	Total	9,640
Indirect Costs		3,170
Contingency		2,560
Monitoring Equipment[b]		573
TOTAL CAPITAL COSTS		15,900
DOWNTIME COST		5,870
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		2,870

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[a] Based on high access/congestion.

[b] Turnkey.

500 feet of new ductwork and new ID fans. Downtime cost is estimated at $5,870,000.

Annual cost are presented in Table 6.2-8. Significant operating cost are for maintenance materials including bag replacement, electricity for the ID fans and slurry atomizers and monitoring instrument maintenance. Total annual cost, including capital recovery and downtime is $4,960,000.

6.2.7 Summary of Control Options

6.2.7.1 Description of Control Costs. The control technologies described in the previous sections have been combined into the 7 retrofit emission control options discussed in Section 3.0. Table 6.2-9 summarizes the combustion, particulate control, temperature control, and acid gas control technologies described in Sections 6.2.3 through 6.2.6 that were combined for each of the control options. It should be noted that since the model plant already achieves best PM control at baseline, Options 1 through 3 are identical.

6.2.7.2 Environmental Performance. The performance of each control option is summarized in Table 6.2-10. For each pollutant, the table presents both the pollutant concentrations and annual emissions. The greatest reduction in total CDD/CDF emissions and in acid gas emissions is achieved with the spray dryer/fabric filter retrofit. Control of CDD/CDF with combustion improvements or dry sorbent injection are approximately equally effective. Greatest overall emission control is achieved when combustion improvements are combined with acid gas control technology. Emissions of CO are affected only by combustion improvement; PM emissions are unchanged for any option, since best control is achieved at baseline. Both dry sorbent injection and spray drying have significant negative waste disposal impacts, increasing plant solid waste by 25 and 22 percent respectively.

6.2.7.3 Costs. The total annualized cost of each option is presented in Table 6.2-11. The cost of each control option increases with increased level of control. The most costly Option 7, at $5,460,000 per year annualized cost, provides 99.8 percent reduction of CDD/CDF, 97 percent reduction of HCl, and 90 percent reduction of SO_2. Less costly options provide lower levels of emission reduction.

TABLE 6.2-8. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 300 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Operating Labor		96
Supervision		14
Maintenance Labor		53
Maintenance Materials		239[a]
Electricity		191
Compressed Air		27
Water		6
Lime		256
Waste Disposal		164
Monitors		215
	Total	1,260
INDIRECT COSTS		
Overhead		213
Taxes, Insurance, and Administration		614
Capital Recovery and Downtime		2,870
	Total	3,700
TOTAL ANNUALIZED COSTS		4,960

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[a] Includes bag replacement costs of $47,000.

TABLE 6.2-9. SUMMARY OF CONTROL OPTIONS FOR SMALL RDF-FIRED MWC MODEL PLANT

			Particulate control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X						
2. Good PM Control with Combustion and Temperature Control	X						
3. Best PM Control and Combustion and Temperature Control	X						
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/Temperature Control	X	X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/Temperature Control	X	X			X		X

TABLE 6.2-10. ENVIRONMENTAL PERFORMANCE SUMMARY FOR SMALL RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units of 300 tpd RDF each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	2000	1000	1000	1000	500	250	20	10
Mg/yr[b]	1.9E-3	9.5E-4	9.5E-4	9.5E-4	4.8E-4	2.4E-4	1.9E-5	9.6E-6
% Reduction vs. Baseline	--	50	50	50	75	88	99	99.5
CO Emissions								
(ppmv)	200	150	150	150	200	150	200	150
Mg/yr	239	119	119	119	418	119	418	119
% Reduction vs. Baseline	--	71	71	71	0	71	0	71
PM Emissions								
(gr/dscf)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	22	22	22	22	22	22	22	22
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
SO_2 Emissions								
(ppmv)	300	300	300	300	150	150	29	29
Mg/yr	819	819	819	819	410	410	78	78
% Reduction vs. Baseline	--	0	0	0	50	50	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	250	250	15	15
Mg/yr	778	778	778	778	390	390	22	22
% Reduction vs. Baseline	--	0	0	0	50	50	97	97
Total Solid Waste								
(tons/day)	60	60	60	60	75	75	80	80
Mg/yr	18,200	18,200	18,200	18,200	22,700	22,700	24,100	24,100
% Increase vs. Baseline	--	0	0	0	25	25	33	33

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[a] All flue gas concentrations are reported on a 7 percent O_2 dry basis. Standard and normal conditions are both 1 atmosphere and 70°F.

TABLE 6.2-11. COST SUMMARY FOR SMALL RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 300 tpd RDF each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	2,370	2,370	2,370	5,660	8,030	15,900	18,300
Downtime Cost	1,960	1,960	1,960	2,930	2,930	5,870	5,870
Annualized Capital and Downtime Cost	569	569	569	1,130	1,440	2,870	3,180
Direct O&M Cost	56	56	56	841	897	1,260	1,320
Total Annual Cost	754	754	754	2,270	2,770	4,960	5,460
Cost Effectiveness ($/ton RDF)	3.77	3.77	3.77	11.40	13.90	24.80	27.30
Facility Downtime (Months)	2	2	2	3	3	6	6
Total Compliance Time (Months)	7	7	7	19	19	25	25

[a] All costs except cost effectiveness given in $1000. All costs in December 1987 dollars.

6.2.7.4 Energy Impacts. Table 6.2-12 presents a summary of the energy impacts associated with the control options. The electrical use figures take into account the cost savings of not operating incremental auxiliary fuel use because auxiliary burners are in place on the model plant and are used under baseline operation.

TABLE 6.2-12. ENERGY IMPACTS FOR SMALL RDF-FIRED COMBUSTOR MODEL PLANTCONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	0	0
4	615	0
5	615	0
6	4,150[b]	0
7	4,150[b]	0

[a] Incremental use from baseline.

[b] Excludes electrical credit of not operating the ESP's.

6.3 REFERENCES

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7.0 MODULAR STARVED-AIR COMBUSTORS

In terms of the number of existing facilities, starved-air modular combustors comprise the largest segment of the MWC population. There are approximately 41 of these facilities in operation. A list of operating facilities is provided in Table 7.0-1. Approximately 75 percent of these facilities were manufactured by Consumat Systems. Other suppliers include Ecolaire, Clear Air, and Kelly Systems.

The population of modular starved-air MWC's can be divided into basic groups: those with unit capacities of greater than or equal to 50 tpd, and smaller units. There are 14 facilities with combustors having a unit capacity of greater than or equal to 50 tpd. These facilities typically employ heat recovery (13 out of 14), have a PM control device (11 out of 14), and are typically newer than the smaller units. The smaller units are less likely to have heat recovery (15 out of 28), typically do not have PM control (4 out of 28), and are generally older.

Based on these differences, two model plants were developed. The first represents a larger facility with heat recovery and PM control (Section 7.1), and the second represents a smaller facility with no heat recovery and no PM control (Section 7.2). Although the larger model is equipped with transfer rams for moving waste through the system, and the smaller model uses reciprocating grates, this distinction is not as important as that of unit size.

A typical modular starved-air MWC is shown in Figure 7.0-1. The basic design includes two separate combustion chambers (referred to as the "primary" and "secondary" chambers). Waste is batch fed to the primary chamber by a hydraulically activated ram. The charging bin is filled by a front-end loader. Waste feeding takes place automatically on a set frequency (generally 6 to 10 minutes between charges).

Waste is moved through the primary combustion chamber by either hydraulic transfer rams or reciprocating grates. Clear Air designs are equipped with grates, and the Consumat, Ecolaire, and Kelly Systems use transfer rams. Systems using transfer rams have individual hearths upon which combustion takes place. Grate systems generally include two separate grate sections. In

TABLE 7.0-1. EXISTING MODULAR STARVED-AIR COMBUSTORS

Plant/Location	Type	Manufacturer	No. of Units	Unit Size (tpd)	Year of Start-Up[a]	Heat Recovery	Air Pollution Control Device
Hampton, SC	Transfer Rams	Consumat	3	90	1985	Yes	Electrostatic Precipitator
Hartford County, MD	Transfer Rams	Consumat	4	90	1987	Yes	Electrostatic Precipitator
Red Wing, MN	Transfer Rams	Consumat	1	90	1982	Yes	Electrostatic Precipitator
Tuscaloosa, AL	Transfer Rams	Consumat	4	75	1984	Yes	Electrostatic Precipitator
Perham, MN	Reciprocating Grate	Clear Air	2	57	1986	Yes	Electrostatic Precipitator
Portsmouth, NH	Transfer Rams	Consumat	4	50	1982	Yes	Fabric Filter
Coos Bay, OR (II)	Transfer Rams	Consumat	1	50	1980	Yes	None
Auburn, ME	Transfer Rams	Consumat	4	50	1981	Yes	Fabric Filter
Dyersburg, TN	Transfer Rams	Consumat	1	50	1986	No	None
Johnsonville, SC	Transfer Rams	Consumat	1	50	NA	Yes	Electrostatic Precipitator
Oneida County, NY	Transfer Rams	Consumat	4	50	1985	Yes	Electrostatic Precipitator
Bellingham, WA	Transfer Rams	Consumat	2	50	1986	Yes	None
Oswego, NY	Transfer Rams	Consumat	4	50	1986	Yes	Electrostatic Precipitator
Batesville, AR	Transfer Rams	Consumat	2	50	1981	Yes	None
Pittsfield, NH	Transfer Rams	Kelly	1	48	NA	No	None
Fergus Falls, MN	Transfer Rams	John Zink	2	47	1988	Yes	Verturi Wet Scrubber
Barron County, WI	Transfer Rams	Consumat	2	40	1986	No	Electrostatic Precipitator
Polk County, MN	Transfer Rams	John Zink	2	40	1988	Yes	Electrostatic Precipitator
Cattaraugus County, NY	Reciprocating Grate	Clear Air	3	38	1983	No	None
Livingston, MT	Transfer Rams	Consumat	2	38	1982	Yes	None
Durham, NH	Transfer Rams	Consumat	3	36	1980	Yes	Cyclone
Blytheville, AR	Transfer Rams	Consumat	2	36	1983	No	None
Center, TX	Transfer Rams	Consumat	1	36	1985	Yes	None
Carthage, TX	Transfer Rams	Consumat	1	36	1985	Yes	None
Windham, CT	Transfer Rams	Consumat	3	36	1981	Yes	Fabric Filter
Miami, OK	Transfer Rams	Consumat	3	35	1982	Yes	None
Newport News, VA	Transfer Rams	Consumat	1	35	1980	Yes	None
Wilton, NH	Transfer Rams	Consumat	1	30	1978	No	None
Fort Leonard Wood, MO	Transfer Rams	ECP Systems	3	26	1982	Yes	None
Windham, ME	Transfer Rams	Consumat	2	25	1973	No	None
North Little Rock, AR	Transfer Rams	Consumat	4	25	1977	Yes	None
Salem, VA	Transfer Rams	Consumat	4	25	1977	Yes	None
Huntsville, TX (DOC)	Transfer Rams	Industronics	1	25	1984	No	None

[a] NA = Information not available.

TABLE 7.0-1. EXISTING MODULAR STARVED-AIR COMBUSTORS
(Continued)

Plant/Location	Type	Manufacturer	No. of Units	Unit Size (tpd)	Year of Start-Up[a]	Heat Recovery	Air Pollution Control Device
Anderson County, TX (DOC)	Transfer Rams	Consumat	1	25	1980	No	None
Grimes County, TX (DOC)	Transfer Rams	Industronics	1	25	1983	No	None
Brazoria County, TX (DOC)	Transfer Rams	Industronics	1	25	1983	No	None
Wrightsville Beach, NC	Transfer Rams	Consumat	2	25	1981	No	None
Osceola, AR	Transfer Rams	Consumat	2	25	1980	Yes	None
Westmoreland County, PA	Transfer Rams	John Zink	2	25	1986	Yes	Electrostatic Precipitator
Cassia County, ID	Transfer Rams	Consumat	2	25	1982	Yes	None
Waxahachie, TX	Reciprocating Grate	Clear Air	2	25	1982	Yes	None
Lincoln, NH	Transfer Rams	Kelly	1	24	1980	No	None
Groveton, NH	Transfer Rams	ECP Systems	1	24	1975	Yes	None
Brookings, OR	Transfer Rams	Consumat	2	24	1979	No	None
Stuttgart, AR	Transfer Rams	Consumat	3	23	1971	No	None
Litchfield, NH	Transfer Rams	Consumat	1	22	NA	No	None
Fort Dix, NJ	Reciprocating Grate	Clear Air	4	20	1986	Yes	Wet Scrubber/Fabric Filter
Plymouth, NH	Transfer Rams	NA	1	16	1975	No	None
Candia, NH	Transfer Rams	Kelly	1	15	1979	No	None
Coos Bay, OR (I)	Transfer Rams	Consumat	2	12.5	1978	No	None
Gatesville, TX (DOC)	Transfer Rams	Consumat	1	12.5	1979	No	None
Canterbury, NH	Transfer Rams	Kelly	1	10	NA	No	None
Wolfboro. NH	Transfer Rams	Consumat	2	8	1975	No	None
Auburn, NH	Transfer Rams	Consumat	1	5	1981	No	None

[a] NA = Information not available.

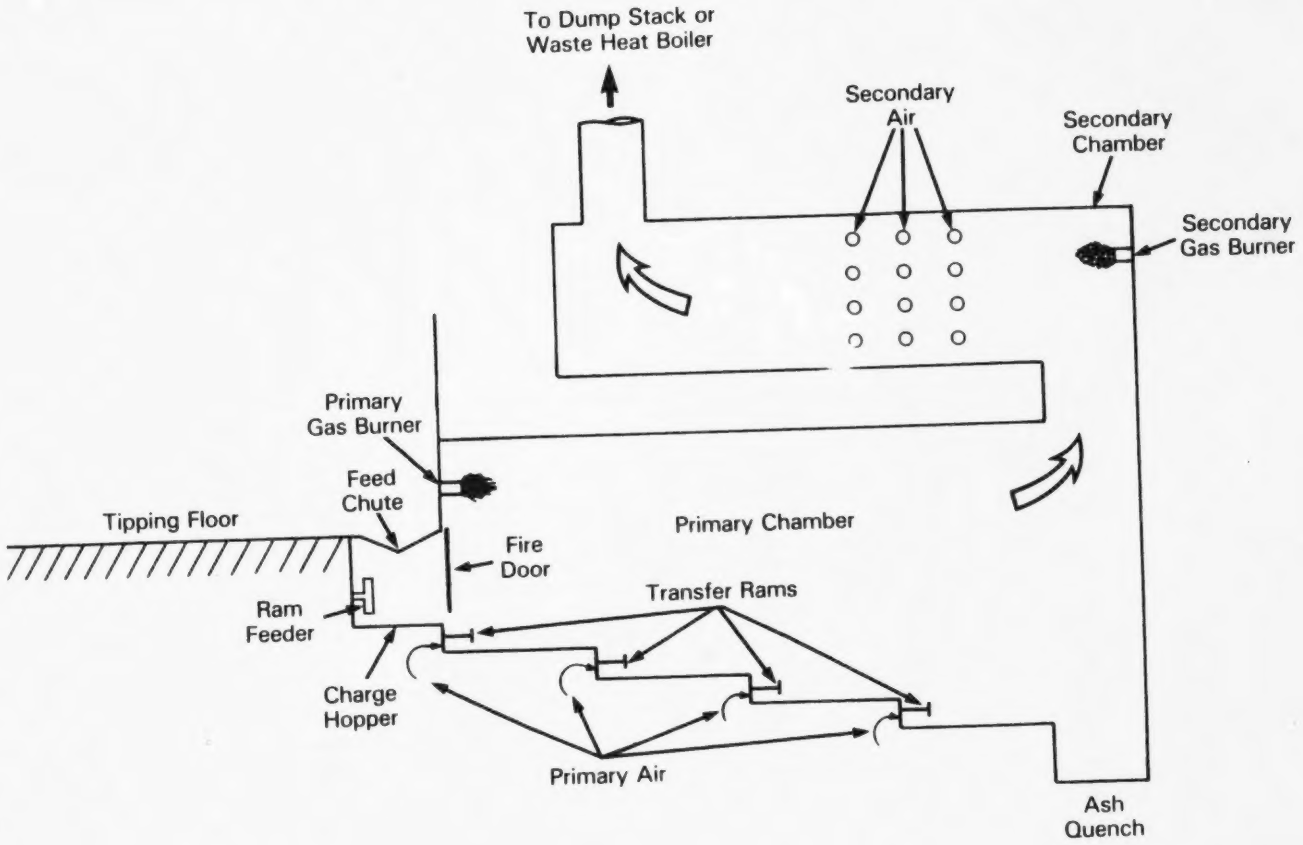

Figure 7.0-1. Typical Modular Starved-Air Combustor with Transfer Rams

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either case, waste retention times in the primary chamber are long--up to 12 hours. Bottom ash is usually discharged to a wet quench pit.

The quantity of air introduced in the primary chamber defines the rate at which waste burns. The primary chamber essentially functions as a gasifier, producing a hot fuel gas which is burned out in the secondary chamber. The combustion air flow rate to the primary chamber is controlled to maintain an exhaust gas temperature set point (generally 1200 to 1400^0F), which normally corresponds to about 40 percent theoretical air. Other system designs operate with a primary chamber temperature between 1600 and 1800^0F, which requires 50 to 60 percent theoretical air.

As the hot, fuel-rich flue gases flow to the secondary chamber, they are mixed with excess air to complete the burning process. The temperature of the exhaust gases from the primary chamber is above the autoignition point. Thus, completing combustion is simply a matter of getting air to the fuel-rich gases. The amount of air added to the secondary chamber is modulated to maintain a desired flue gas exit temperature, typically 1800 to 2200^0F. Approximately 80 percent of the total combustion air is introduced as secondary air, so that excess air levels for the system are about 100 percent. Typical operating ranges vary from 80 to 150 percent excess air.

The walls of both combustion chambers are refractory-lined. Early starved-air modular combustors did not include heat recovery, but a waste heat boiler is common in newer installations, with two or more combustion modules manifolded to a boiler. Combustors with heat recovery capabilities also maintain dump stacks for use in emergency, or when the boiler is not in operation.

Most modular starved-air MWC's are equipped with auxiliary fuel burners which are located in both the primary and secondary combustion chambers. Auxiliary fuel can be used during start-up or when problems are experienced in maintaining desired combustion temperatures. In general, the combustion process is self-sustaining through control of air flows and feed rate, so continuous co-firing of auxiliary fuel is normally not necessary.

As mentioned above, temperature controllers are used to maintain desired combustion air flows. Some of the newer modular MWC's preheat the secondary combustion air by drawing it through a shroud surrounding the primary chamber, using the radiant heat from the primary chamber to heat the flue gases.

The current guideline elements for good combustion practices in modular starved-air MWC's are presented in Table 7.0-2. Under normal operating conditions, a starved-air combustor will have no trouble maintaining 1800^{0}F in the secondary combustion chamber. However, due to some State requirements for retention time of several seconds at 1800^{0}F, some designs are including a larger secondary combustion chamber.

With the increase in heat recovery, downstream flue gas temperature control may become an important issue for modular starved-air MWC's. More systems are using heat recovery boilers and adding ESP's for particulate control, and in some cases the ESP temperatures may be in the range that will promote formation of CDD/CDF. One facility (Tuscaloosa, AL) has installed an economizer in the ducting just upstream of the existing ESP. In addition to lowering the flue gas temperature prior to the ESP, the plant also has increased steam production by 5 to 10 percent, so that the economizer will pay for itself after 5 years of operation.

Although the operation/control components listed in Table 7.0-2 are generally attainable by all operating facilities, there are some verification measures which are lacking in most starved-air modular MWC's. For example, air flows are not directly measured, and oxygen monitors are typically installed only when a boiler is used. Continuous CO monitors are also not very common.

In general, emissions of air pollutants from modular starved-air MWC's are relatively low. Low gas velocities in the primary combustion chamber prevent carryover of excessive particulate, so that uncontrolled emissions are lower than mass burn or RDF systems. The high combustion temperatures and sufficient mixing of flue gases with air in the secondary combustion chamber provide good combustion, resulting in relatively low CO and trace organic emissions. However, the high temperatures and lack of air pollution controls are a concern with regard to emission of trace elements.

TABLE 7.0-2 COMPONENTS OF GUIDELINES - GOOD COMBUSTION PRACTICES FOR MINIMIZING TRACE ORGANIC EMISSIONS FROM MODULAR STARVED-AIR MWC'S

Element	Component
Design	Temperature at fully mixed location
	Secondary air capacity
	Secondary air injector design
	Auxiliary fuel capacity
	Downstream flue gas temperature
Operation/Control	Excess Air
	Turndown restrictions
	Start-up procedures
	Use of auxiliary fuel
Verification	Oxygen in flue gas
	CO in flue gas
	Furnace temperature
	Temperature at APCD inlet
	Adequate air distribution

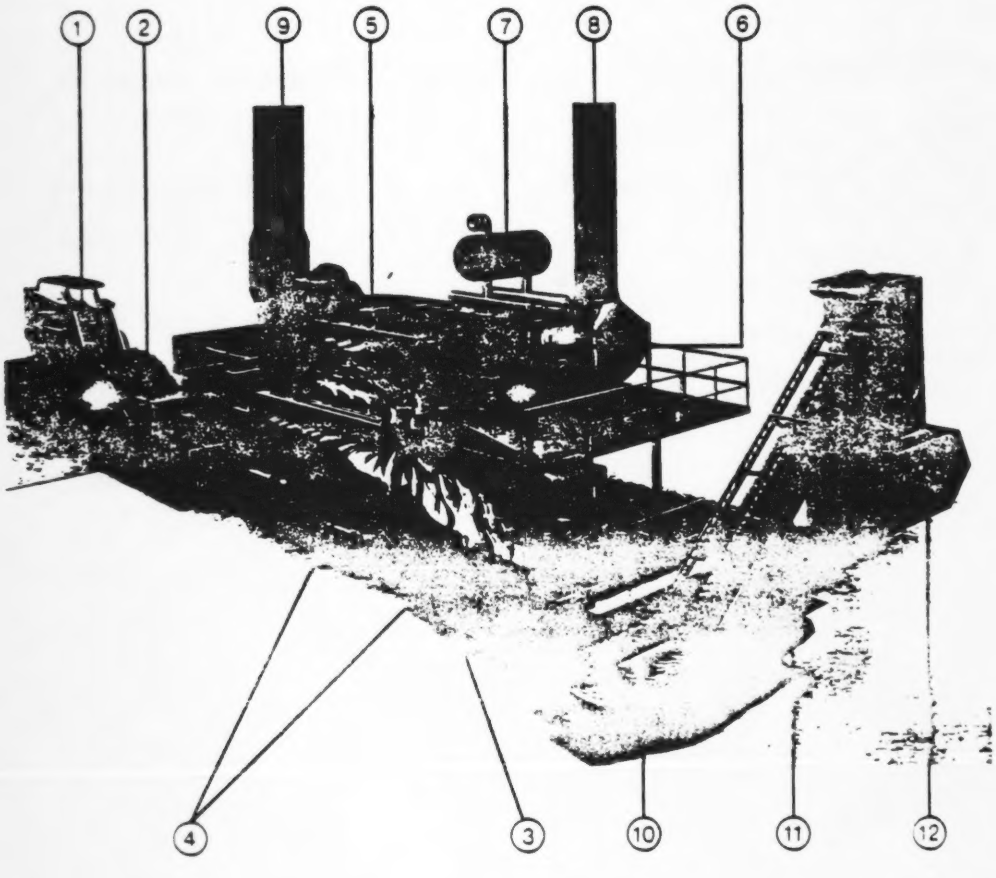
7.1 LARGE MODULAR STARVED-AIR COMBUSTOR WITH TRANSFER RAMS

This section presents the case study results for a model large (unit size ≥ 50 tpd) modular starved-air MWC equipped with transfer rams. As shown in Table 7.0-1, there are 41 known plants in this sub-category. This subpopulation is dominated by the Consumat system (31 plants). Section 7.1.1 presents a description of the Tuscaloosa Energy Recovery Facility, a Consumat plant which was visited in order to gather information for model development. Section 7.1.2 presents a description of the model plant. Sections 7.1.3 through 7.1.6 detail the retrofit modifications, estimated performance, and costs associated with various control options. Section 7.1.7 presents a summary of the control options which are discussed in more detail in Section 3.0 of this report.

7.1.1 Description of the Tuscaloosa, AL Plant[1]

The Tuscaloosa Energy Recovery Facility (TERF) consists of four Consumat model #CS3000 combustors, each with a design rating of 75 tons of municipal solid waste (MSW) per day. Figure 7.1-1 presents a cutaway view of the standard Consumat incinerator, and Table 7.1-1 presents Tuscaloosa plant design data. The facility and has a contract to deliver steam to the B.F. Goodrich plant located adjacent to the facility. The B.F. Goodrich land where the TERF is sited, is leased to the TSWA for 20 years. The term of the steam delivery contract is for 10 years beginning from facility start-up in March 1984.

The TERF until recently operated on a 5-day/week schedule. However, because the B.F. Goodrich plant now operates 7-days/week, the TERF operates on Saturdays approximately 50 percent of the time. The current contract requires that the TERF provide B.F. Goodrich with 50,000 lb/hr of steam (26.65×10^6 lb/month). B.F. Goodrich pays a fixed price for up to 26.65×10^6 lb/month of steam and a reduced price for any additional. The feedwater is supplied by Goodrich. The first four modules in the boilers were replaced one year ago due to erosion and corrosion, after three years operation. Each of the boilers is designed to produce 32,500 lb/hr of steam, all of which is delivered to B.F. Goodrich. The plant currently employs 21 people on a 5-day/week, 24-hr/day operating schedule.



The above cutaway view of the standard CONSUMAT® energy-from-waste module shows how material and hot gas flows are controlled to provide steam from solid waste. A skid steer tractor (1) pushes the waste to the automatic loader (2). The loader then automatically injects the waste into the gas production chamber (3) where transfer rams (4) move the material slowly through the system. The high temperature environment in the gas production chamber is provided with a controlled quantity of air so that gases from the process are not burned in this chamber but fed to the upper or pollution control chamber (5). Here the gases are mixed with air and controlled to maintain a proper air fuel ratio and temperature for entrance into the heat exchanger (6) where steam is produced. A steam separator (7) is provided to ensure high quality steam. In normal operation gases are discharged through the energy stack (8). When steam is not required or in the event of a power failure, hot gases are vented through the dump stack (9). The inert material from the combustion process is ejected from the machine in the form of ash into the wet sump (10) and conveyed (11) into a closed bottom container (12) which can then be hauled to the landfill for final disposal.

Figure 7.1-1. Typical Consumat Module

TABLE 7.1-1. TUSCALOOSA, ALABAMA DESIGN DATA

Combustor:	
Type	- Modular Starved air
Number of Combustors	- 4 Consumat #CS=3000
Combustor Unit Capacity	- 75 tpd (each)
Total Plant Capacity	- 300 tpd
Number of Boilers	- 2 Richmond Engineering Waste Heat Boilers
Boiler Design Rate	- 32,000 lb/hr steam (each)
Emission Controls:	
Type	- Electrostatic Precipitator
Number of Precipitators	- 1
Number of Fields	- 2
Inlet design particulate loading	- 0.10 gr/dscf at 12% CO_2
Operating Temperature	- 450°F
Design Collection Efficiency	- 50 percent
Particulate Emission Limit	- 0.08 gr/dscf at 12% CO_2
Gas Flow	- 90,000 acfm

Goodrich also supplies 12 to 15 tons per day of waste in the form of automobile tire rejects from their adjacent production plant. When the TERF does not generate steam, the Goodrich plant increases their plant steam generation. Currently, due to the low cost of natural gas, the Goodrich plant generates steam at a lower cost than the TERF.

7.1.1.1 Combustor Design and Operation. Waste is delivered to the plant and dumped on a tipping floor where mixing and fuel feeding is executed by front-end loaders. The front-end loaders deliver a charge to the furnaces by dumping the waste into one of four waste loaders (Consumat #ML1400MS). Each of the furnaces operates on a 5-minute charging cycle (12 charges/hr). The furnace operator responds to a green light signal on a panel which indicates that the loader is ready to receive a charge. The panel also indicates whether the charge of waste to the loader should be heavy, normal, or light. After the waste has been placed in the loader, the operator presses a button which closes the loader top door and activates an automatic charging sequence. When the door closes, the fire door opens and the ram extends, charging the waste into the primary combustion chamber. When the feed stroke is complete, the ram retracts and the fire door closes. The loader door opens and is then ready for an additional waste load. To prevent ignition of the waste in the loader, a water mist curtain is activated when the furnace is opened for charging. The loader is not completely air tight, but observations of the charging cycle indicated that a fairly good seal is maintained by the waste itself during the periodic intervals when the fire door is open.

Waste is moved through the primary combustion chamber by three transfer rams which are located on the floor of the primary combustion chamber. In addition, an ash ram discharges the bottom ash from the primary chamber into a water filled quench pit. The floor of the primary chamber is stepped so that waste moves down from one hearth to another as the transfer rams operate. Waste retention times in the primary chamber are 6 to 8 hours, and waste volumes are reduced by approximately 90 percent. The bottom ash is removed from the quench pit by a drag chain conveyor which dumps the wet ash into a bin for the landfill.

The primary combustion chamber operates at sub-stoichiometric conditions with sufficient combustion air added to maintain an exit temperature of 1200 to 1400°F. To prevent slagging conditions that occur with temperatures greater than 1400°F, the State permit requires that primary chamber temperatures not exceed 1400°F. In order to maintain this temperature requirement, combustion airflows to the primary chamber are limited to about 40 percent of theoretical air. Primary chamber air enters the combustion chamber through water cooled air tubes integrated with the transfer rams. The primary chamber is constructed with a double shell. Secondary chamber air is preheated by drawing it through the shell and contacting it with the wall of the primary chamber, resulting in less heat loss from the primary chamber and enhancing burnout in the secondary. The secondary air is introduced into the chamber of orifices along the circumference of the chamber (excluding the floor). Burnout of volatiles is accomplished in the chamber by adding sufficient excess air to provide good mixing with the flue gases. Secondary chamber temperatures are generally in the range of 1800-2000°F. Air flows are not measured directly. Pressures are recorded in the supply headers downstream of the control dampers for both the primary and secondary air supplies, and these readings are displayed in the control room for each unit. There is no continuous O_2 monitor so excess air levels are not directly measured. However, typical overall excess air levels are 100 percent. Temperatures are monitored continuously in both the primary and secondary chambers, and are the primary variables for monitoring operation of the units. Temperatures are maintained by varying air flows and fuel feeding rates.

Combustion products exit the secondary chamber and are directed to one of two waste heat boilers. The first boiler is paired with the #1 and #2 furnaces and the second boiler with #3 and #4.

Each of the waste heat boilers consists of nine steam generating modules and one module in an economizer section. Pressure components for the boilers were fabricated by Richmond Engineering. These were assembled and cabinets were manufactured by Consumat. The two boilers manifold into a common duct which originally ran the length of the building to an electrostatic precipitator. Last year a small economizer was installed in this ducting upstream of the ESP. This modification has increased feedwater temperature to the boilers by about 100°F and increased boiler efficiency for a given waste feed rate. In addition, the flue gas temperatures entering the ESP have been reduced approximately 100 to 150°F. The economizer outlet temperatures are currently in the 450 to 500°F range.

Gas burners are located in both the primary and secondary combustion chambers, and in the ducting between the economizer and the ESP. Gas is fired to bring the secondary chamber up to 600°F during process start-up. Normally the primary chamber burners are not used even during system start-up.

7.1.1.2 Emission Control System Design and Operation. The flue gas from all four incinerators at the TERF exits the economizer in a single duct. This duct passes through the facility building wall to a 2-field electrostatic precipitator (ESP). (Table 7.1-1 also shows ESP design information). The ESP was designed to achieve 50 percent control. The ESP typically reduces emissions by over 50 to 60 percent, achieving an emission rate of 0.05 to 0.07 gr/dscf adjusted to 12 percent CO_2.

The ESP outlet flue gas is continuously monitored by an opacity meter, as required by the facility permit. A weekly report is submitted to the State Department of Environmental Management detailing repairs made to the ESP, ESP electrical readings and the opacity strip charts. Plant upset conditions resulting in increased emissions must be reported within 24 hours. If three 1-hour average opacity readings exceed 15 percent in a 24-hour period, a stack test must be performed within 10 days of the occurrence. This test is used to determine if the facility meets the permit emission limit of 0.08 gr/dscf adjusted to 12 percent CO_2. Two recent compliance sampling episodes showed particulate emissions of 0.07 gr/dscf corrected to 12 percent CO_2.

The facility has experienced corrosion problems with the ESP due to the condensation of acid gases that occurs with facility shutdown and start-up. This corrosion problem resulted in the replacement of the ESP internals after three years of operation. The facility now maintains a higher ESP flue gas temperature (>250°F) during shutdown/start-up using a gas fired burner located in the ducting before the ESP. If the facility goes to a 7-day/week operation, the potential for corrosion problems will also be reduced.

Currently, the ESP ash is being handled and disposed of as a hazardous waste. However, it is anticipated that in the future the bottom and fly ash handling equipment will be modified so that both wastes can be disposed of in a conventional landfill. Current landfill waste disposal costs are approximately $13 to $18/ton.

7.1.2 Description of Model Plant

7.1.2.1 Combustor Design and Operation. Due to the prevalence of the Consumat design in the existing population of modular starved air MWC's, it is assumed that the model plant is designed to incorporate the features found in most Consumat or similar designs. Model plant design data are shown in Table 7.1-2. The model plant consists of three 50 tpd modules, each with a primary and secondary combustion chamber. The individual flues manifold to a single waste heat boiler where the gas temperature is reduced to 315^{0}C (600^{0}F) (see Figure 7.1-2). It is assumed that only two of the three combustors operate simultaneously. The normal operating schedule is 24-hours/day, 7-days/week. The larger operating schedule typically incorporate waste heat recovery capabilities, so it is assumed that heat recovery is in place at the model.

Waste feeding is accomplished automatically by a hydraulic ram. Waste is delivered to the feeding bin in batches by a front-end loader. The ram feeding frequency is controlled automatically. The waste is moved through the primary chamber by five water-cooled transfer rams that periodically extend and retract, pushing the waste along a series of burning hearths. The frequency of the transfer ram stroke is controlled automatically. The waste retention time in the primary chamber is approximately 10 to 12 hours.

Holes in the transfer rams provide the flow of primary air to waste. It is assumed that 40 percent of theoretical air is used in the primary chamber, and primary chamber exit temperatures are maintained in the range of 1200 to 1400^{0}F. At 40 percent of theoretical air, approximately

TABLE 7.1-2. MODEL PLANT BASELINE DATA FOR LARGE MODULAR STARVED-AIR COMBUSTOR

Combustor:	
Type	Modular Starved-air
Number of Combustors	3 (2 units operate with 1 on standby)
Combustor Unit Capacity	50 tpd
Total Plant Capacity	150 tpd
Emission Controls	
Type	Electrostatic Precipitator
Number	1[a]
Number of Fields	2
Inlet Temperature	600°F
Collection Efficiency	67 percent
Gas Flow	29,000 acfm
Total Plate Area	2200 ft^2
SCA at 29,000 acfm and 600°F	75
Emissions:[b]	
CDD/CDF (tetra-octa) (stack)	600 ng/dscm
PM (stack)	0.05 gr/dscf[c]
CO	100 ppmv
HCl	500 ppmv
SO_2	200 ppmv
Stack Parameters:	
Height	60 feet
Diameter	5.5 feet
Operating Data:	
Remaining Plant Life	$\geq$ 20 years
Annual Operating Hours	8,000 hours
Annual Operating Cost	$976,000/year

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[a] One ESP controls emissions from entire plant. Three units are ducted to the single ESP and stack. The ESP is sized for two units operating simultaneously.

[b] All emissions are dry, corrected to 7 percent O_2. Standard and normal conditions are both 1 atmosphere and 70°F. All values except PM and CDD/CDF are at the boiler exit.

[c] Inlet PM emissions to the ESP are 0.1 gr/dscf at 7 percent O_2.

1,200 scfm of air is supplied in the primary chamber. The fuel-rich combustion gases exit the primary chamber through a vertical breeching and flow into the secondary chamber.

Additional air is added in the secondary chamber through rows of wall jets which are located at two axial locations in the chamber. Secondary air is preheated by drawing it through a shroud which surrounds the primary chamber, and the secondary air flow rate is controlled automatically to maintain a minimum chamber exit temperature of 1800^{0}F. With the secondary chamber operating at approximately 80 percent excess air, the total system operates at 100 percent excess air, and total flow rates leaving the secondary combustion chamber are approximately 6,400 dscfm for each unit. With two units operating simultaneously, total gas flow exiting the waste heat boiler is 12,800 dscfm.

The combustors are equipped with auxiliary fuel burners in both the primary and secondary chambers. Temperatures are monitored continuously in both chambers, and temperature control is accomplished by automatic modulation of combustion air flows. Air flow pressures are recorded in the supply ducting for both primary and secondary air flows. There are no continuous O_2 or CO monitors in place.

7.1.2.2 Emission Control System Design and Operation. As shown in Table 7.0-1, the larger Consumat units that employ heat recovery are typically equipped with an ESP for particulate control. The Tuscaloosa plant has a single 2-field ESP with PM emissions ranging from 0.04 to 0.08 gr/dscf at 12 percent CO_2. Most existing plants are equipped with a 2-field ESP; therefore, the model plant is equipped with a single 2-field ESP controlling emissions to 0.05 gr/dscf corrected to 7 percent O_2. Since all three modules are ducted to a single boiler and ESP, there is also a single stack. Table 7.1-2 gives ESP operating data and stack parameters. A plot plan of the model plant is shown in Figure 7.1-2.

7.1.2.3 Environmental Baseline. Table 7.1-2 also presents baseline emissions data for the model plant. Baseline emissions data are assumed for the model based on a review of existing emissions data for plants similar in design. All emissions are reported at the boiler outlet, corrected to 7 percent O_2. Uncontrolled CDD/CDF emission levels are 400 ng/dscm measured at the boiler exit. Research indicates that ESP's operating in

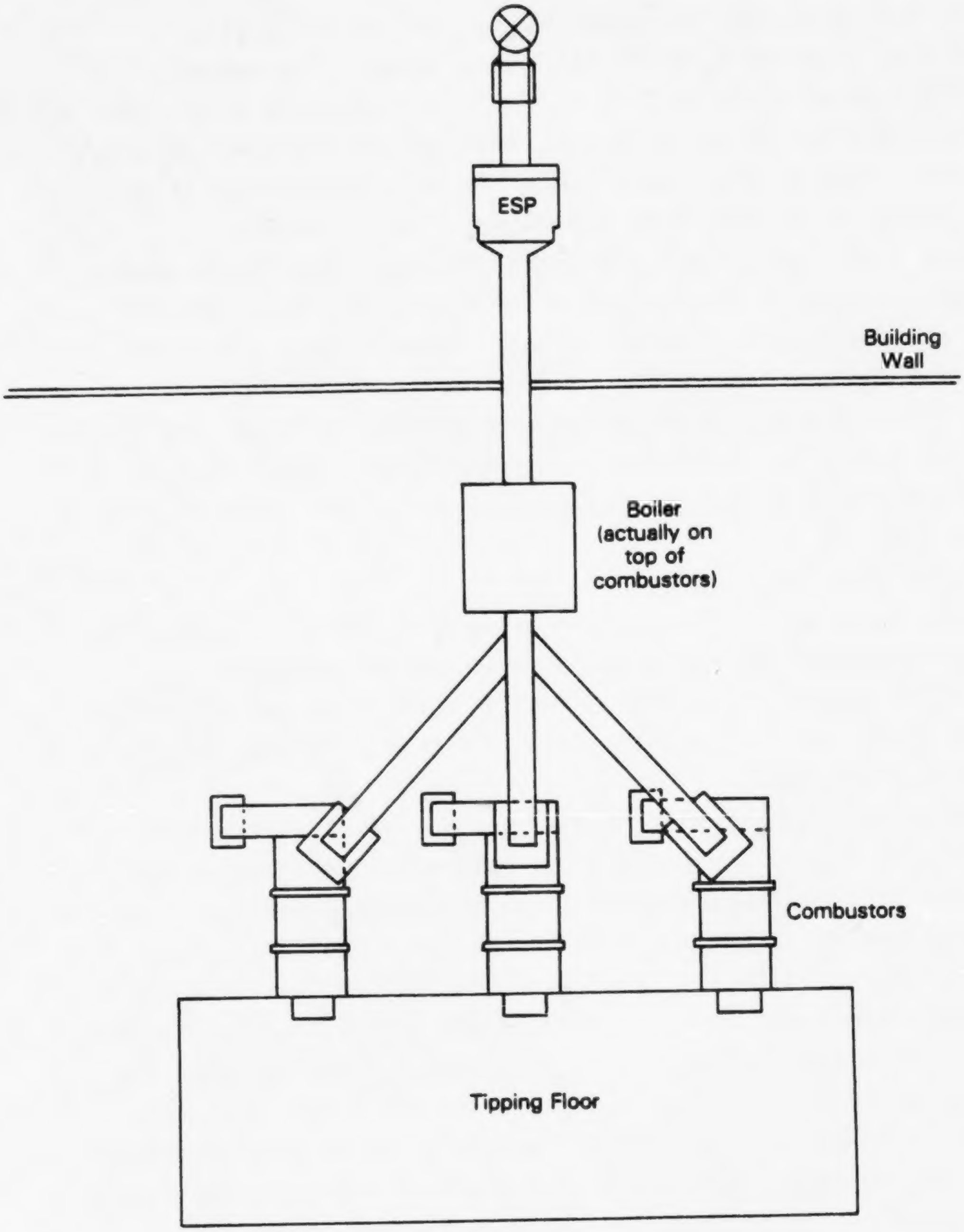

Figure 7.1-2. Plot Plan of Model Plant

the 500 to 600^{0}F temperature range promote formation of CDD/CDF and can increase exit concentrations by 50 percent over combustor exit levels. Therefore, the model plant is assumed to have CDD/CDF emissions of 600 ng/dscm at 7 percent O_2 at the stack under baseline conditions.

Particulate emissions are 0.15 gr/dscf uncontrolled and 0.05 gr/dscf at the stack. Uncontrolled CO, HCl and SO_2 emissions are 100 ppmv, 500 ppmv and 200 ppmv, respectively. Waste volume reductions are assumed to be 90 percent, and weight reductions are assumed to be 70 percent.

7.1.3 Good Combustion Control. The model plant is judged to have good combustion practices in place. This is reflected by the relatively low baseline emission levels at the boiler exit. However, some additional verification elements (monitoring) are required to provide the operators with a means of maintaining desired emission performance levels, and there is also a potential for downstream formation of trace organics to occur. Discussion is provided below regarding corrective actions needed to minimize these problems.

7.1.3.1 Description of Modifications

Verification Measures. Continuous monitoring of CO and O_2 is necessary to verify good combustion and operation at prescribed excess oxygen levels. These monitors should be installed in ducting prior to the boiler in order to monitor conditions in each unit. The monitors will include integrators and readouts in the control room.

Downstream Temperature Control. The flue gas temperatures entering the ESP will be reduced from 600^{0}F to 450^{0}F. The recommended modification involves installation of a separate economizer with adequate heat transfer surface to achieve the required temperature reduction. It is assumed that space between the boiler and the ESP is adequate to allow installation. Figure 7.1-3 shows the location of the proposed economizer. A bypass duct will be included so that when repairs to the economizer are needed, a damper can direct flue gases around the economizer into the ESP. The result of this modification is that the flue gases are rapidly cooled to temperatures below which CDD/CDF may form, and the ESP, where residence times and particulate concentrations are higher, does not experience the temperature which promotes formation.

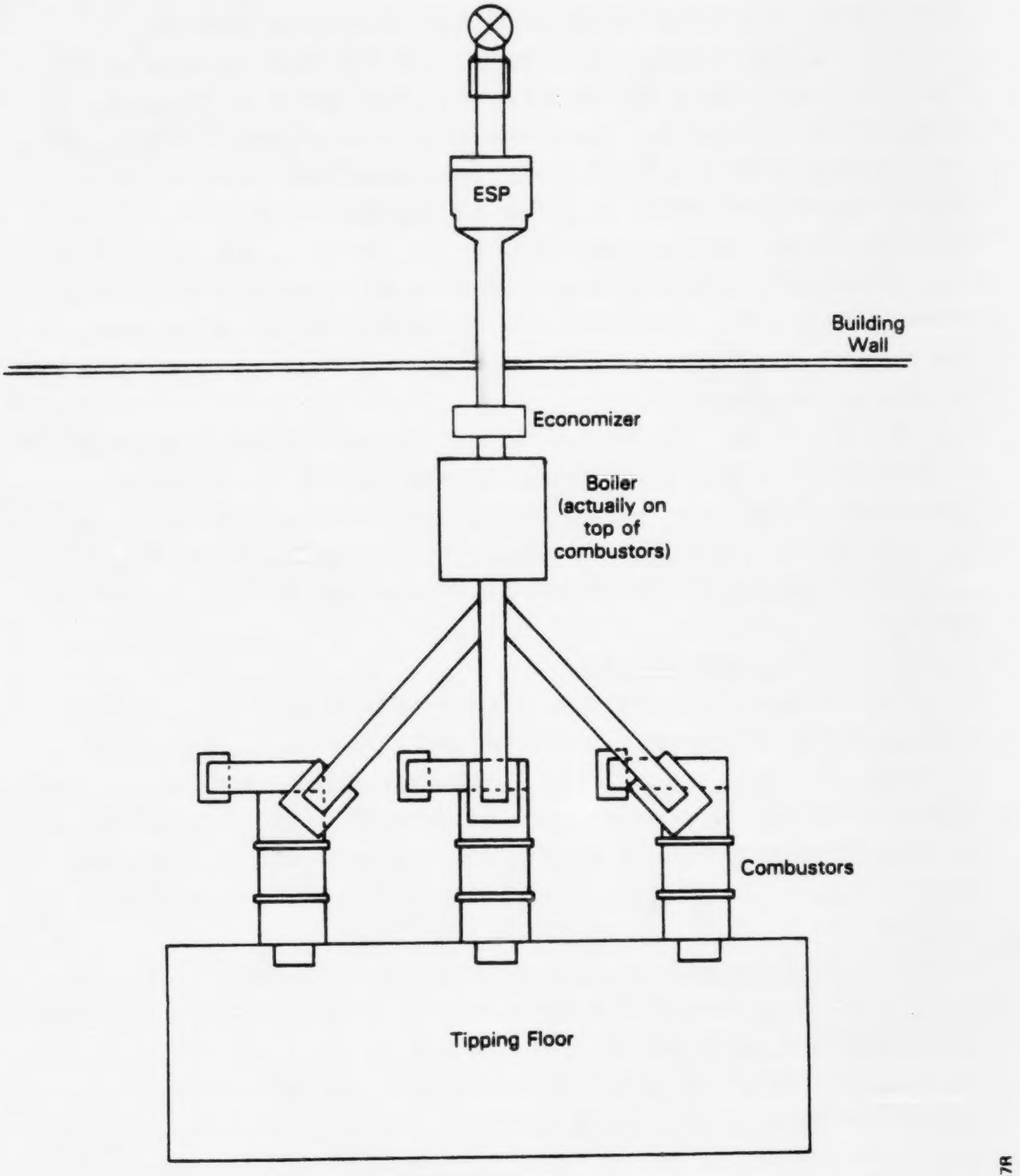

Figure 7.1-3. Combustion modification equipment location.

Retrofit Considerations. It is estimated that the modifications can be completed during a scheduled outage with no unscheduled downtime.

7.1.3.2 Environmental Performance. The modifications required for the model plant will reduce CDD/CDF emission to 400 ng/dscm at the stack, corrected to 7 percent O_2. These reductions are a result of dropping the flue gas temperatures below the range where downstream formation of CDD/CDF has been observed. At a flue gas temperature of 450°F, CDD/CDF emissions at the stack are assumed to be the same as at the combustor exit.

The monitors will provide the operators with a means of preventing excess air emissions by alerting them to the need for corrective action in the event of poor operating conditions. The modifications do not affect PM or acid gas emissions.

7.1.3.3 Costs. The capital costs of the modifications are presented in Table 7.1-3. Total capital costs for the retrofit are $270,000. Annualized capital costs are $36,000 per year, based on a 15-year plant life and a 10 percent interest rate. Annual costs are presented in Table 7.1-4. Total annualized costs, including O&M and annualized capital, are $182,000 per year.

7.1.4 Best Particulate Control

The ESP in place on the model plant reduces PM by 62 percent, from 0.15 gr/dscf to 0.05 gr/dscf (corrected to 7 percent O_2). Since good combustion practices are judged to already be in place, no change in inlet grain loading will be produced by combustor modifications. Therefore, the baseline PM emission rate is equal to the rate identified with moderate control (0.05 gr/dscf), and no plant modifications will be required for this control level.

7.1.4.1 Description of Modifications. To achieve good particulate matter control (0.01 gr/dscf emission rate) with good combustion practices and temperature control to 450°F will require an ESP with 5,400 square feet of collection area. Since the required area is two and a half times the area of the existing ESP, adding collection plates to the existing ESP is not a practical way to achieve the desired performance. Instead, the existing ESP will be demolished and replaced with a new ESP of adequate size.

TABLE 7.1-3. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS
(Three units of 50 tpd each)

Item	Cost ($1,000)
DIRECT COSTS:	
Economizer with Feedwater System and Duct Modifications	45
Oxygen and CO Monitors with Readouts and Integrators	135
Total	180
INDIRECT COSTS AND CONTINGENCIES:	90
TOTAL CAPITAL COSTS	270
DOWNTIME COST	0
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	36

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[a] All costs are in December 1987 dollars.

TABLE 7.1-4. PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Three units of 50 tpd each)

Item	Cost ($1,000)
DIRECT COSTS:	
Operating Labor	0
Maintenance Labor	42
Maintenance Materials	42
Total	84
INDIRECT COSTS:	
Overhead	51
Taxes, Insurance, and Administration	11
Capital Recovery and Downtime	36
Total	98
TOTAL ANNUALIZED COST	182

Fifty feet of new duct and a new ID fan will also be required. The new ESP will be erected in the same general area as the existing ESP; a plot plan is shown in Figure 7.1-4. No new monitoring equipment will be installed. Downtime will affect all three units at once and is estimated to be one month.

7.1.4.2 Environmental Performance. Particulate matter emissions will be reduced from 0.05 gr/dscf to 0.01 gr/dscf. The increased fly ash recovery will add 12 tons per year to the baseline solid waste disposal requirements for the plant.

7.1.4.3 Costs. Capital cost requirements for particulate control upgrade are shown in Table 7.1-5. Demolition of the existing ESP will cost $400,000. The other major capital item is the PM control equipment. Total capital cost is $1,480,000. Downtime cost will be $162,000. Annual costs are dominated by capital recovery and annualized downtime cost and are expected to be $298,000 per year. Annual costs are presented in Table 7.1-6.

7.1.5 Good Acid Gas Control.

7.1.5.1 Description of Modifications. For good acid gas control, hydrated lime will be injected into the flue gas duct before the ESP. The lime sorbent will be fed at a molar ratio of 2:1 (calcium to acid gas) for a total rate of 113 lb/hr with two units operating. Additional plant equipment will include a sorbent storage silo, a pneumatic sorbent transfer system, a sorbent feed bin, and pneumatic injection nozzles. To cool the flue gas from 450°F to 350°F, spray nozzles also located in the duct before the ESP will introduce 2 to 3 gpm of water. If an economizer is not present as the result of installing good combustion modifications, 6 to 7 gpm of cooling water will be required to cool the flue gas from 600°F to 350°F. Fifty feet of new duct will be fabricated to contain the new water and sorbent nozzles.

A total of 10,800 square feet of ESP collection area will be required to collect the sorbent and fly ash with the economizer in place. Approximately 11,400 total square feet will be needed if combustor modifications have not been made. Again, the existing 2200 square foot ESP is not salvageable and will be demolished to make room for a new ESP.

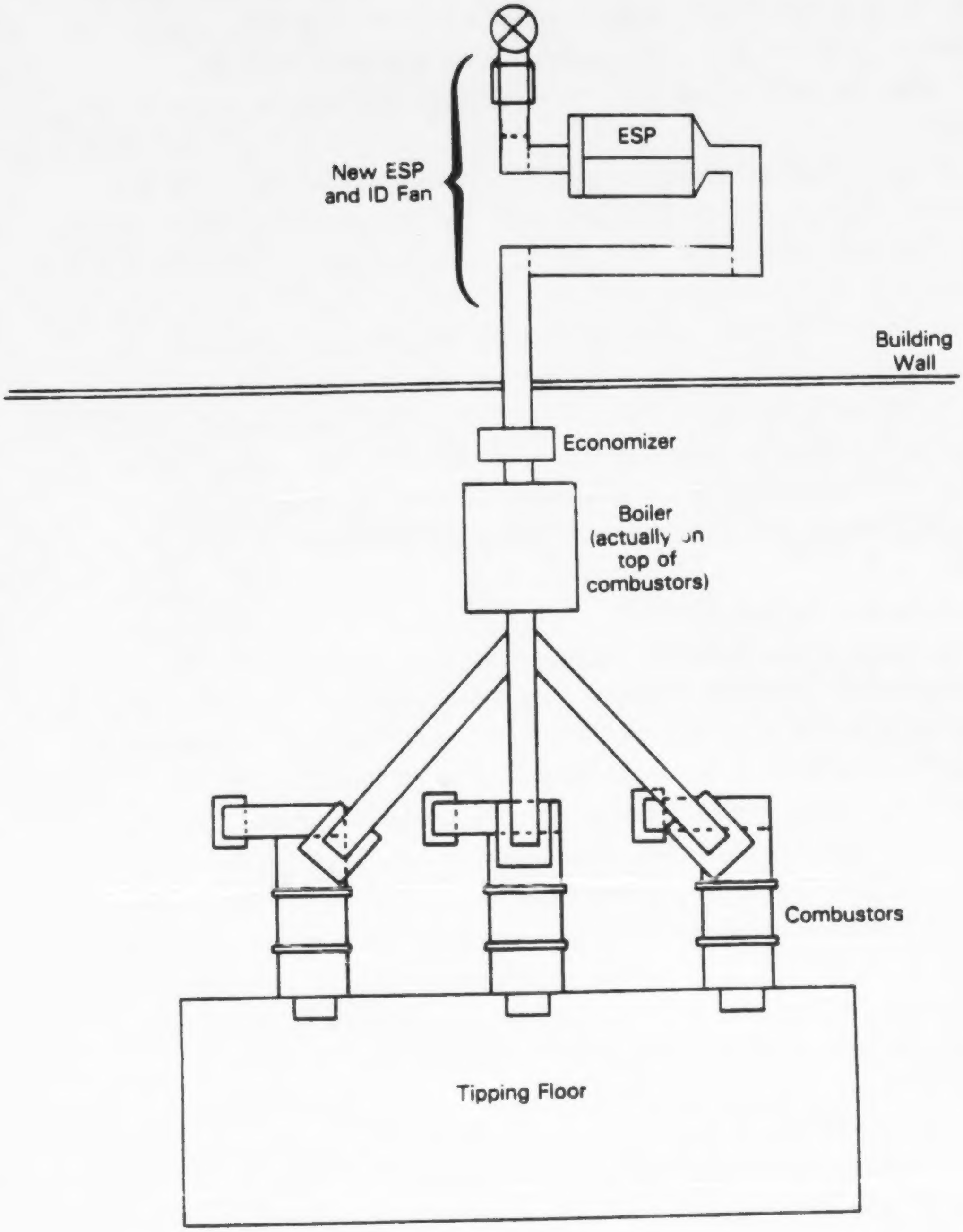

Figure 7.1-4. Particulate control equipment arrangement.

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TABLE 7.1-5. PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS (Three units of 50 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
PM Control[a]	
Upgrade Costs	594
Access/Congestion Cost	198
New Flue Gas Ducting[a]	
Ducting Costs	12
Access/Congestion Cost	3
Other Equipment	
Fan	49
Stacks	0
Demolition/Relocation	400
Total	1,210
Indirect Costs and Contingencies	275
Monitoring Equipment	0
TOTAL CAPITAL COST	1,480
DOWNTIME COST	154
ANNUALIZED CAPITAL RECOVERY	215

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[a] Based on moderate access/congestion.

TABLE 7.1-6. PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROLS
(Three units of 50 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	1
Electricity	2
Water	0
Waste Disposal	0
Monitors	0
Total	3
INDIRECT COSTS:	
Overhead	19
Taxes, Insurance, and Administration	60
Capital Recovery and Downtime	215
Total	294
TOTAL ANNUALIZED COST	297

Installation of a new ESP will also require 50 feet of new duct and a new ID fan. The proposed equipment arrangement is shown in Figure 7.1-5. New monitoring equipment for SO_2, HCl, O_2 and CO_2 is also included. Downtime is expected to be approximately one month.

7.1.5.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced 75 percent from boiler outlet levels. Reduced ESP operating temperatures will prevent additional formation in the ESP, so expected total CDD/CDF emissions of 100 ng/dscm are expected. Acid gas emissions will be reduced 80 percent for HCl and 40 percent for SO_2. Particulate matter emissions will be reduced from 0.05 gr/dscf to 0.01 gr/dscf. Additional collected fly ash and sorbent will add 595 tons per year of solid waste to the plant baseline disposal requirements.

7.1.5.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 7.1-7 for baseline and good combustion practices. Total capital cost is $2,480,000 with baseline combustion and $2,450,000 with good combustion. Most of the cost is associated with new equipment for particulate and temperature control, though $400,000 is included for demolition of the existing ESP. A moderate access/congestion level is assumed for all new equipment installation.

Annual costs are presented in Table 7.1-8. The major operating costs are associated with lime purchase and with operation and maintenance of the process monitors. Total annual cost of dry sorbent injection, including annualized capital and downtime is $726,000 with baseline combustion and $719,000 with good combustion.

7.1.6 Best Acid Gas Control.

7.1.6.1 Description of Modifications. To achieve greater reductions in CDD/CDF, HCl and SO_2, a spray dryer/fabric filter system will be installed in place of the existing ESP. A total of 100 feet of new duct will be used to connect the new equipment to the existing stack. The proposed equipment configuration is shown in Figure 7.1-6.

Lime slurry will be introduced into the spray dryer at a calcium-to-acid gas ratio of 2.5:1. Water in the lime slurry equivalent to 8 gpm is needed to cool the gas stream from 600 to 300^{0}F. The spray dryer installed with good combustion would introduce only 4 gpm, since the economizer exit gas is already cooled to 450^{0}F.

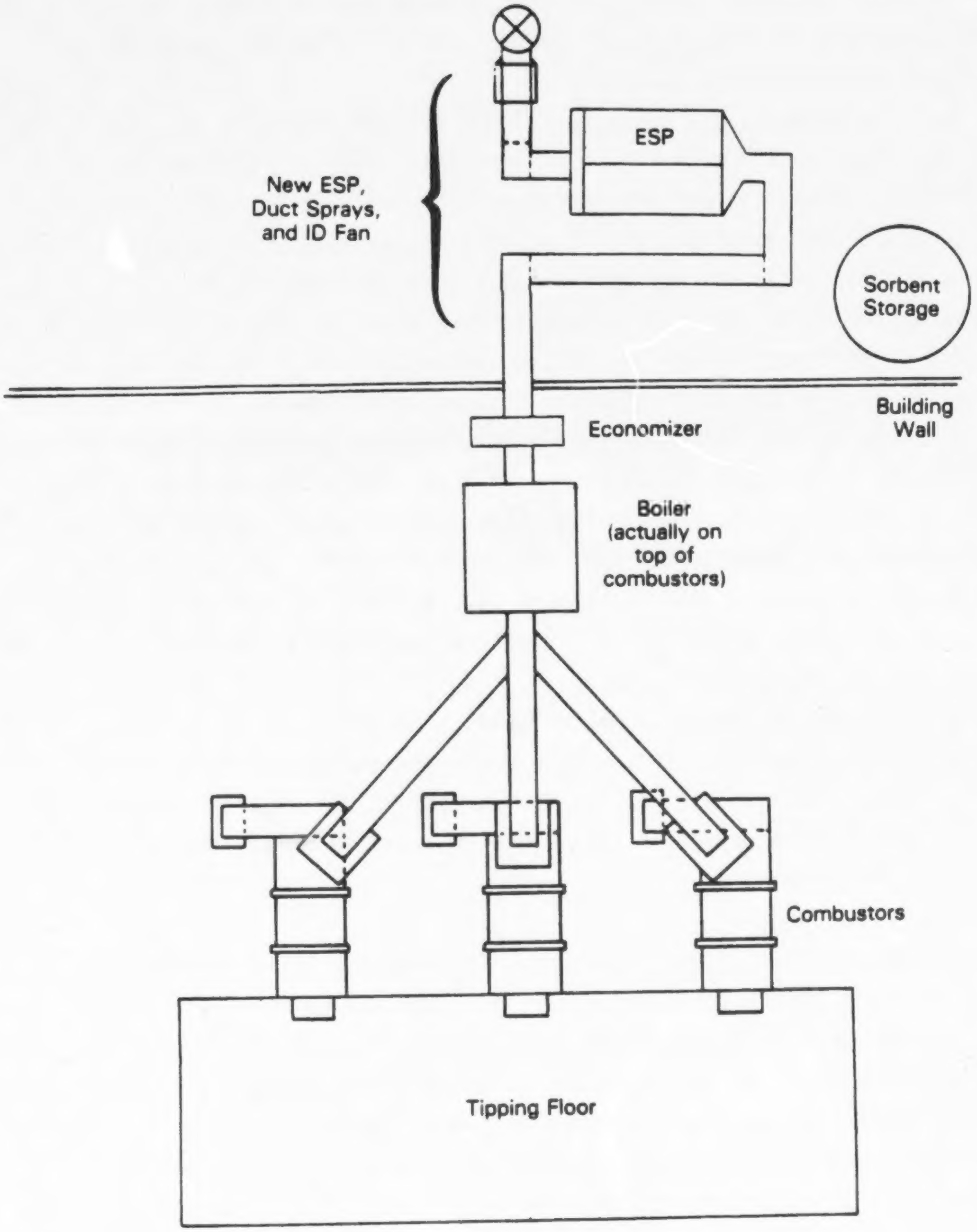

Figure 7.1-5. Dry sorbent injection equipment arrangement.

TABLE 7.1-7. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH NEW ESP (Three units of 50 tpd each)

Item	Cost ($1000) Baseline Combustion Practices	Cost ($1000) Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control[a]		
Equipment	169	169
Access/Congestion Cost	17	17
Particulate and Temperature Control[b]		
Equipment	835	824
Access/Congestion Cost	174	172
New Flue Gas Ducting[a]		
Ducting Cost	27	25
Access/Congestion Costs	9	9
Other Equipment		
Fans	47	45
Stacks	0	0
Demolition/Relocation	400	400
Total	1,680	1,660
Indirect Costs and Contingencies	538	532
Monitoring Equipment[c]	257	257
TOTAL CAPITAL COST	2,480	2,450
DOWNTIME COST	154	154
ANNUALIZED CAPITAL RECOVERY	346	342

[a] Based on moderate access/congestion.

[b] Based on high access/congestion for temperature control ductwork.

[c] Turnkey.

TABLE 7.1-8. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH NEW ESP (Three units of 50 tpd each)

Item	Cost ($1000)	
	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Operating Labor	30	30
Supervision	5	5
Maintenance Labor	14	14
Maintenance Materials	13	13
Electricity	17	16
Water	2	1
Lime	36	36
Waste Disposal	16	16
Monitors	103	103
Total	236	234
INDIRECT COSTS:		
Overhead	55	55
Taxes, Insurance, and Administration	89	88
Capital Recovery and Downtime	346	342
Total	490	485
TOTAL ANNUALIZED COST	726	719

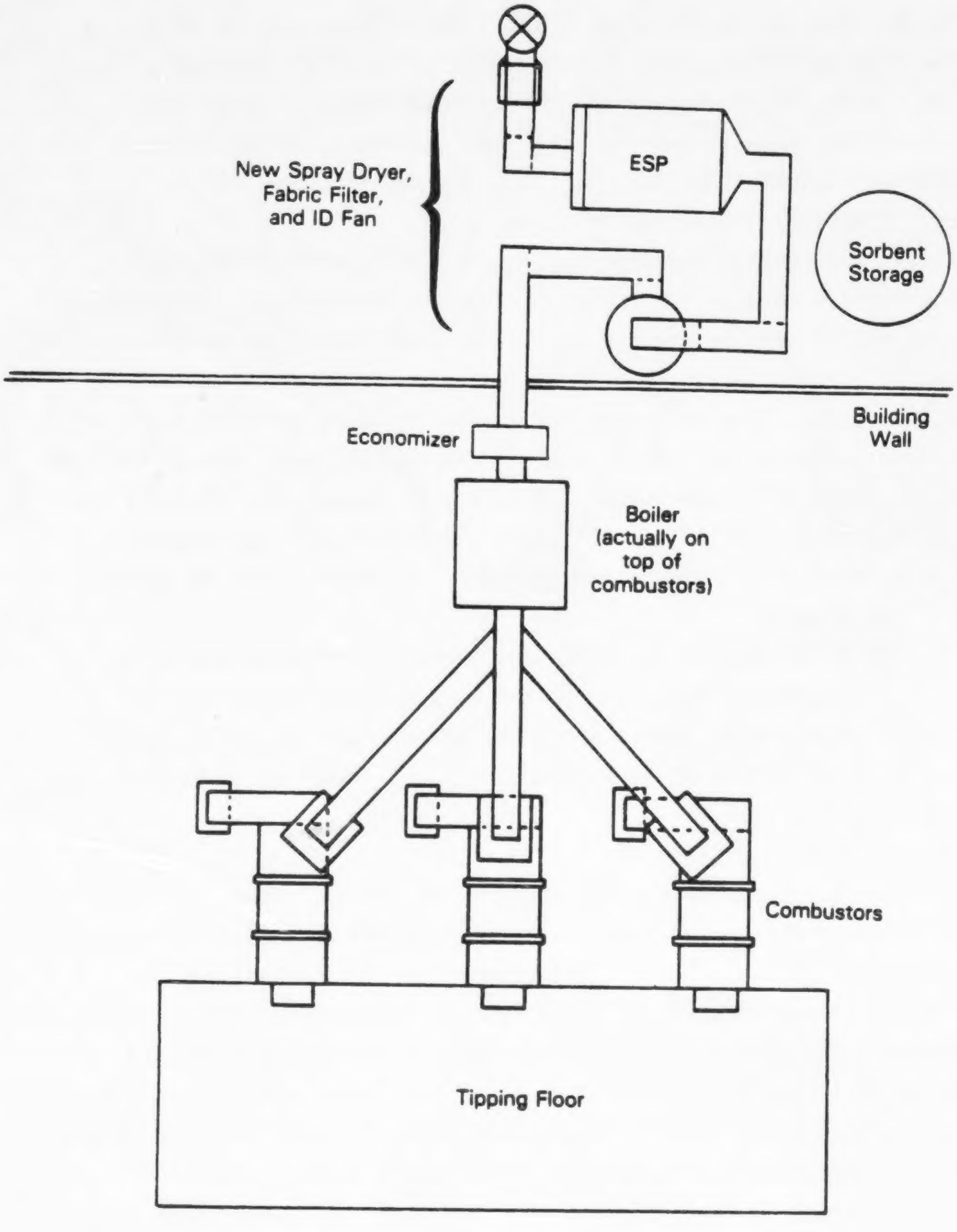

Figure 7.1-6. Spray dryer/fabric filter equipment arrangement.

The lime receiving, storage and slurry area is also shown in Figure 7.1-6. The fabric filter will have 7,300 square feet of effective cloth area with good combustion or 7,600 square feet with baseline combustion. Both filters have a net air-to-cloth ratio of 4:1. The increased pressure drop of fabric filter over ESP will require a new ID fan. New monitoring equipment for HCl, SO_2, CO_2, O_2 and opacity will be installed. Downtime is expected to be one month.

7.1.6.2 Environmental Performance. CDD/CDF emission reductions of 99 percent or to 5 ng/dscm (whichever is higher) are expected. Emissions of particulate matter will be reduced to 0.01 gr/dscf. Acid gas emissions will be reduced 90 percent for SO_2 and 97 percent for HCl.

7.1.6.3 Costs. Capital costs for installing a spray dryer/fabric filter system are shown in Table 7.1-9. Total capital costs are $4,490,000 with baseline combustion and $4,200,000 with good combustion. These figures include purchased equipment, installation, ESP demolition, and indirect costs such as engineering and contingencies. A moderate level of access/congestion was assumed.

Annual costs are presented in Table 7.1-10. Significant operating costs are for maintenance materials including bag replacement, and for maintenance of the process monitors. Total annual cost including capital recovery and annualized downtime is $1,180,000 with baseline combustion, and $1,120,000 with good combustion.

7.1.7 Summary of Control Options

7.1.7.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 7.1-11 summarizes the combustion, particulate control, and acid gas control technologies described in Sections 7.1.3 through 7.1.6 that were combined for each of the control options described in Section 3.0. It should be noted that since the model plant already achieves good PM control at baseline, Options 1 and 2 are identical.

7.1.7.2 Environmental Performance. The performance of each control option is summarized in Table 7.1-12. For each pollutant, the table presents both the pollutant concentrations and emissions. The greatest reductions in acid gases, particulate matter, and total CDD/CDF are all

TABLE 7.1-9. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 50 tpd each)

Item	Costs ($1000) Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control		
Equipment	1,840	1,700
Access/Congestion Cost	459	424
New Flue Gas Ducting		
Ducting Cost	26	25
Access/Congestion Cost	7	6
Other Equipment		
Fans	56	48
Stacks	0	0
Demolition/Relocation	400	400
Total	2,780	2,600
Indirect Costs	787	726
Contingency	634	585
Monitoring Equipment[a]	286	286
TOTAL CAPITAL COST	4,490	4,200
DOWNTIME COST	154	154
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	610	573

[a] Turnkey.

TABLE 7.1-10. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 50 tpd each)

Item	Cost ($1000) Baseline Combustion Practices	Cost ($1000) Good Combustion Practices
DIRECT COSTS:		
Operating Labor	48	48
Supervision	7	7
Maintenance Labor	26	26
Maintenance Materials	55[a]	51[a]
Electricity	40	32
Compressed Air	5	4
Water	2	1
Lime	30	30
Waste Disposal	20	20
Monitors	107	107
Total	341	328
INDIRECT COSTS:		
Overhead	78	75
Taxes, Insurance, and Administration	152	140
Capital Recovery and Downtime	610	573
Total	840	788
TOTAL ANNUALIZED COST	1,180	1,120

[a] Includes bag replacement costs of $7,000.

TABLE 7.1-9. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 50 tpd each)

Item	Costs ($1000)	
	Baseline Combustion Practices	Good Combustion Practices
DIRECT COSTS:		
Acid Gas Control		
Equipment	1,840	1,700
Access/Congestion Cost	459	424
New Flue Gas Ducting		
Ducting Cost	26	25
Access/Congestion Cost	7	6
Other Equipment		
Fans	56	48
Stacks	0	0
Demolition/Relocation	400	400
Total	2,780	2,600
Indirect Costs	787	726
Contingency	634	585
Monitoring Equipment[a]	286	286
TOTAL CAPITAL COST	4,490	4,200
DOWNTIME COST	154	154
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	610	573

[a] Turnkey.

TABLE 7.1-11. SUMMARY OF CONTROL OPTIONS FOR LARGE MODULAR STARVED-AIR COMBUSTOR

Control Option Description	Combustion Modifications	Temperature Control	Particulate Control		Acid Gas Control		
			Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X	X					
2. Good PM Control with Combustion Control	X	X					
3. Best PM Control and Combustion and Temperature Control	X	X		X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control	X	X			X		X

TABLE 7.1-12. ENVIRONMENTAL PERFORMANCE SUMMARY FOR LARGE MODULAR STARVED-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Three units of 50 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	600	400	400	400	100	100	5	5
Mg/yr[b]	7.8E-5	5.1E-5	5.1E-5	5.1E-5	1.3E-6	1.3E-6	6.5E-7	6.5E-7
% Reduction vs. Baseline	--	33	33	33	83	83	99	99
CO Emissions								
(ppmv)	100	100	100	100	100	100	100	100
Mg/yr	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	14.8	14.8	14.8	3.0	3.0	3.0	3.0	3.0
% Reduction vs. Baseline	--	0	0	80	80	80	80	80
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	74	74	74	74	44	44	7	7
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	105	105	105	105	21	21	3	3
% Reduction vs. Baseline	--	80	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	30	30	30	30	31.8	31.8	32.3	32.3
Mg/yr	9,090	9,090	9,090	9,100	9,630	9,630	9,800	9,800
% Increase vs. Baseline	--	0	0	0	6	6	8	8

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[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Standard and normal conditions are both 1 atmosphere and 70°F.

achieved with the spray dryer/fabric filter system. The next most effective control for all these pollutants is the dry sorbent injection. Both sorbent addition technologies increase solid waste slightly (less than 10 percent above baseline). The CO emissions remain unchanged, at 100 ppm, for all control options.

7.1.7.3 Costs. The total annualized cost of each option is presented in Table 7.1-13. The most costly control option is Option 7, the spray dryer/fabric filter installation with the economizer for temperature control. Total annual cost for Option 7 is $1,300,000 per year. Overall, the costs of each option are higher for successively higher levels of control.

7.1.7.4 Energy Impacts. Table 7.1-14 presents a summary of the energy impacts associated with the control options. The energy use figures shown are incremental use relative to baseline. The energy savings from not operating the existing ESP are taken into account. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and are used under baseline operation. Note that there is a considerable electrical penalty for the spray dryer/fabric filter option (Option 6 vs. 7) for temperature control with humidification instead of the economizer installation. The fan cost is increased because of increased gas volume, from the injected water, which must be pulled through the fabric filter.

TABLE 7.1-13. COST SUMMARY FOR LARGE MODULAR STARVED-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 50 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	270	270	1,750	2,480	2,720	4,490	4,470
Downtime Cost	0	0	154	154	154	154	154
Annualized Capital and Downtime Cost	36	36	251	346	378	610	609
Direct O&M Cost	84	84	87	236	318	341	412
Total Annual Cost	182	182	479	726	901	1,180	1,300
Cost Effectiveness ($/ton MSW)	3.64	3.64	9.58	14.50	18.00	23.6	26.0
Facility Downtime (Months)	0	0	1	1	1	1	1
Total Compliance Time (Months)	4	4	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in 1987 dollars.

TABLE 7.1-14. ENERGY IMPACTS FOR LARGE MODULAR STARVED-AIR COMBUSTOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	35.1	0
4	345	0
5	336	0
6	885[b]	0
7	709[b]	0

[a] Increase from baseline consumption.

[b] Excludes the electrical credit for not operating the ESP's.

7.2 SMALL MODULAR STARVED-AIR COMBUSTOR WITH RECIPROCATING GRATES

This section presents the retrofit case study results for a small (unit size < 50 tpd) modular starved-air MWC with reciprocating grates. As shown in Table 7.0-1, four existing facilities are represented by this model with unit sizes varying from 25 to 38 tpd. Section 7.2.1 describes of the Waxahachie, TX, facility, which was visited to gather information for model development. Section 7.2.2 describes of the model plant. Sections 7.2.3 through 7.2.8 detail the retrofit modifications, estimated performance, and costs associated with each control option. Section 7.2.9 summarizes the control options, which are discussed in more detail in Section 2.0 of this report.

7.2.1 Description of the Waxahachie Facility[2]

The Waxahachie waste-to-energy plant consists of two modular MWC's, each with capacity to burn 25 tons of municipal solid waste (MSW) per day. The units are two-chamber designs with starved-air conditions in the primary chamber and burnout of gases in the secondary. The units manifold to a single-pass firetube boiler and exhaust gases exit the system with no further treatment. The plant operates both units at full capacity from 11:00 p.m. Sunday until noon the following Saturday, with routine maintenance taking place during downtime. The plant accepts residential and some commercial (no industrial) waste. Due to limitations on storage and burning capacities, MSW is regularly routed to the landfill.

The plant was constructed and began operations in 1982 using a Synergy grate system supplied by Clear Air. When the waste plant was in the planning/construction phase, a steam delivery contract was established with International Extrusion, a subsidiary of International Aluminum. Extrusion agreed to purchase 15,000 lb/hr (or its total requirement, if less) of 100 psi steam. The price of steam was based on the cost of the least expensive fossil fuel available to Extrusion, which was natural gas. Process modifications at Extrusion have continually reduced the steam demands from the waste facility over the last five years. It was uneconomical for the plant to continue to produce so little steam for Extrusion, and the City finally dissolved the contract in August 1987. The boiler is currently idle and flue gases are being vented to the dump stacks until an alternate steam contract is secured. The plant is in negotiating with an adjacent production plant to establish a new contract for steam sales. If this contract is secured it may result in 7-day/week operation for the waste-fired plant.

7.2.1.1 Combustor Design and Operating Procedures. Trucks deliver waste and dump it on the tipping floor where large bulky items are separated. A front end loader mixes the waste and charges each furnace. Each unit is equipped with an automatic loader which holds approximately 2.5 bucket loads from the front end loader. When waste is charged and the top door of the loader closes an automatic charging sequence begins. The fire door opens and a ram extends, pushing the fuel into the primary combustion chamber. The ram then retracts and the fire door closes. When the loader top door opens, it is then ready to receive another charge. The timing cycle is set manually and usually operates every four minutes. The seal on the loader is not tight, and the inside of the furnace can be seen through a 1-inch gap during charging. However, based on a visual inspection, it appeared that there are few other points of air inleakage to the system.

The primary chamber is 22′-9" long by 7′-4" wide. It contains two separate grate sections separated by a vertical drop of about one foot. The sections are sloped 15^0 from horizontal, and each is equipped with an individual air plenum and reciprocating grates which work by way of a rack and pinion. Grate speeds are set manually to achieve good waste burnout. The reciprocating action is controlled by a Texas Instruments controller (Model TI5). Grate siftings are conveyed to the quench pit by drag conveyers. Bottom ash is discharged from the lower grate section to the water-quenched pit which is also equipped with a drag conveyer. Bottom ash is buried in the local landfill. Burnout appears to be fairly good based on visual observation of the bottom ash, and ash disposal quantities are reported to be about four tons of ash per 50 tons of garbage (92 percent weight reduction).

The original Synergy grates were wedge-shaped cast iron with a 2-inch nose on the lower portion. This nose (combined with the 15^0 slope) resulted in waste being pushed through the system too rapidly, and burnout became a problem. This has been resolved by replacing the Synergy grates with the flat 1/2-inch steel plates which are cut and drilled on site.

Separate forced draft fans supply combustion air to the primary and secondary chambers. Air flows are not measured directly for either the primary or the secondary supplies. Thermocouples located at the exit of each chamber provide a signal to the computer controller that results in an automatic adjustment to each air system supply damper, thus maintaining a temperature set point. Primary air is supplied at low velocity through the grates and the estimated retention time of gases in the primary chamber is 1.2 seconds.

Typical operating temperatures in the primary chamber vary from 1600 to 1800^0F. The primary chamber contains a gas burner which is fired for about 2 to 3 hours during process start-up. Constant pressure is maintained in the primary chamber by the induced draft fan, which automatically adjusts a damper setting based on a pressure reading from the primary chamber. A negative draft (approximately -0.2" H_2O) is maintained to avoid fugitive emission episodes.

The secondary combustion chamber has a volume of 265 cubic feet and a gas residence time of 0.8 seconds. High-velocity air is injected into the chamber through 16 holes, each 0.75 inches in diameter, located on a ring around the circumference at the entrance to the chamber. A second nozzle, four inches in diameter, injects additional air from the same header at a side wall location approximately three feet downstream of the radial ring. At the exit of the secondary chamber there are two nozzles, each six inches in diameter, which supply cooling air before the flue gases exit the chamber. A single forced-draft fan supplies all of the secondary air for one furnace. Neither of the secondary air fans were operating during the visit. Plant personnel indicated that the induced-draft fan usually created enough draft to pull secondary air into the chamber at the required flow rate. A secondary chamber gas burner fires automatically as needed to maintain a temperature setting in the secondary chamber. The set point temperature is usually near 1800^0F. The flue gases exiting each secondary chamber may either be discharged through individual dump stacks, or manifolded and ducted to the firetube boiler and discharged through a single stack.

When the boiler is operating, 60 percent of delivered steam is returned as condensate. Water treatment is performed on site. Discussions with plant personnel concerning maintenance indicated that the firetube boiler has performed adequately when operated. Tubes are cleaned once per week with a wire brush.

7.2.1.2 Emission Control System Design and Operation. No air pollution control device (APCD) is currently in place. The Plant Manager stated that the unit is stack tested for particulate matter emissions yearly by the State Air Control Board, but the results have not been forwarded to the plant. Smoke emissions were less than 5 percent opacity during the 4 hours of the visit.

7.2.2 Description of Model Plant

7.2.2.1 Combustor Design and Operation. The model facility consists of two 25-tpd modular combustors that operate 5 days per week, 24 hours per day. Typical of most smaller modular starved-air MWC's, there is no heat recovery in place at the model facility. Rather than transfer rams, grates are used to move the waste through the primary combustion chamber. A plot plan of the model plant is shown in Figure 7.2-1.

Each unit consists of refractory-lined primary and secondary combustion chambers connected by a vertical breeching. Waste is fed to the primary chamber by a hydraulic ram. The ram frequency is adjusted manually and controlled automatically. The primary chamber contains two reciprocating grate sections that move the waste through the system. The grates have separate sets of underfire air plenums which provide primary air at substoichiometric conditions. Primary air flows are adjusted automatically to maintain the primary chamber temperature at 1600°F. The distribution of air to each of the plenums can be manually adjusted. Grate speeds are manually set and adjusted.

The fuel-rich gases from the primary chamber flow through the refractory breeching into the secondary chamber, where they are mixed with high pressure secondary air to complete the combustion process. Excess air quantities are supplied in the secondary chamber so that the combined air supply system provides 100 percent excess air. At 100 percent excess air, total air flow exiting the secondary chamber is approximately 3400 scfm (3200 dscfm) per unit. The primary and secondary air flow rates are controlled automatically

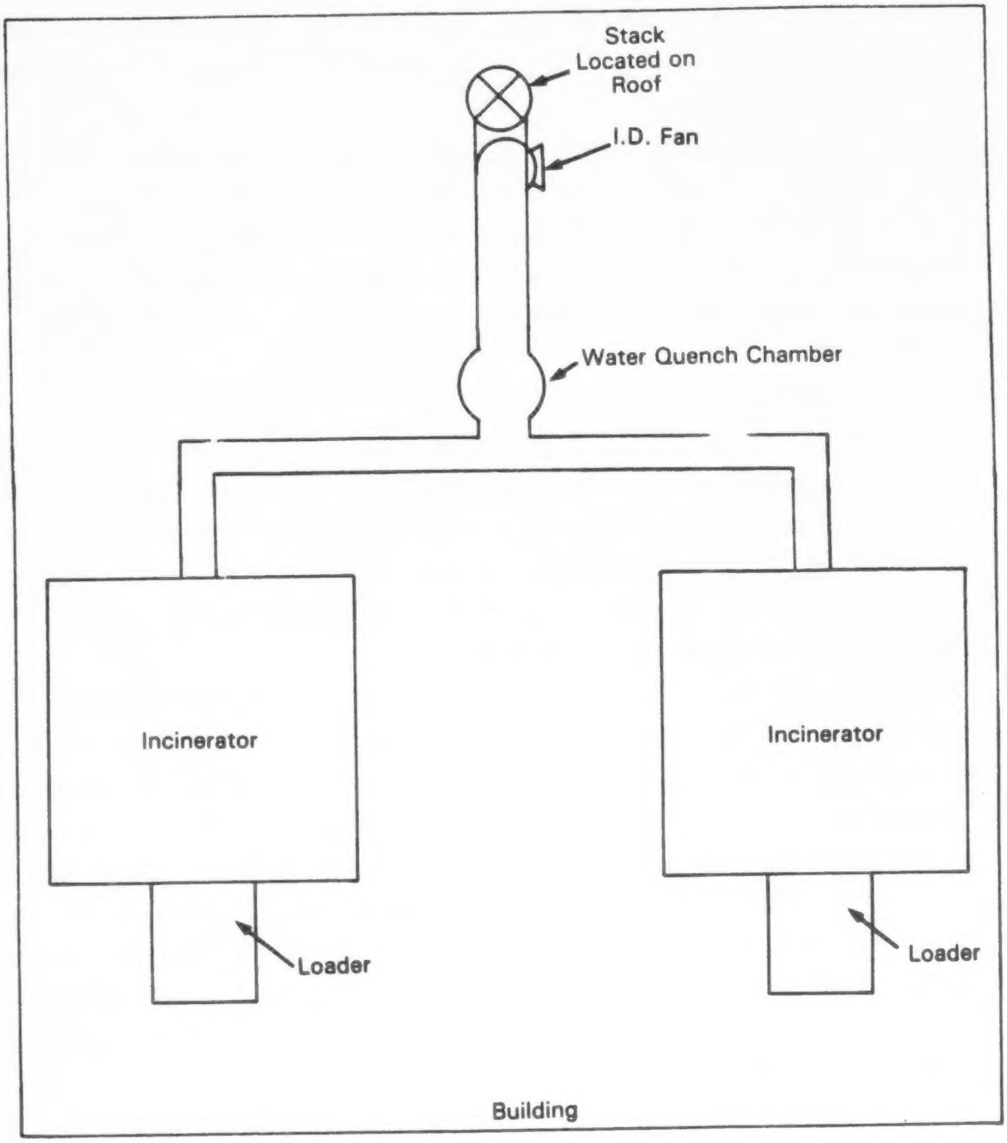

Figure 7.2-1 Plot Plan of Model Plant

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in response to temperature readings in each combustion chamber. The desired temperature set points are 1600°F at the exit of the primary chamber and 1800°F at the exit of the secondary chamber. Auxiliary fuel burners are located in each chamber and are used during start-up. There are no continuous flue gas monitors in place at the model plant. The combustor exhaust gases are manifold from the exit of the secondary combustion chamber to a water quench chamber, where they are cooled to 450°F before being discharged to the atmosphere through a single stack.

7.2.2.2 Emission Control System and Operation. The model plant is not equipped with an APCD. As shown in Table 7.0-1, small modular starved-air plants typically are not equipped with any air pollution control devices (APCD's). For retrofitting new APCD's, a moderate access and congestion level is assumed. It is assumed that this level is typical for plants in this subcategory. For this case study, one APCD will be costed based on the combined flue gas flow rate of both combustors.

7.2.2.3 Environmental Baseline. Table 7.2-1 presents baseline emission data for the model plant. The model plant is assumed to have CDD/CDF emission 400 ng/dscm, corrected to 7 percent O_2. Both uncontrolled PM and CO emissions are assumed to be relatively low (0.15 gr/dscf and 100 ppmv, at 7 percent O_2, respectively) which indicate good combustion practices are essentially in place. Uncontrolled HCl and SO_2 emissions are estimated to be 500 and 200 ppmv at 7 percent O_2, respectively. It is assumed that the combustion process reduces waste volume by 90 percent and weight by 70 percent.

7.2.3 Good Combustion Control

7.2.3.1 Description of Modifications. With the exception of some verification measures, the model plant is judged to have good combustion practices in place. This is reflected by the relatively low baseline emissions. Operating practices are assumed to be kept within the limits of the combustor design specifications. The recommended modifications are limited to the installation of continuous CO and O_2 monitors in the stack to provide verification of good combustion and proper excess air levels. The monitors should be installed with integrators and readout in the control

TABLE 7.2-1. MODEL PLANT BASELINE DATA FOR SMALL MODULAR STARVED-AIR MWC WITH RECIPROCATING GRATES

Combustor:	
Type	Modular Starved-Air, Reciprocating Grate
Number of Combustors	2
Combustor Unit Capacity	25 tpd
Emission Controls	None
Flue Gas Flow Rate[a]	15,500 acfm at 1800°F
Emissions:[b]	
CDD/CDF (tetra-octa)	400 ng/dscm
PM (stack)	0.15 gr/dscf
CO	100 ppmv
HCl	500 ppmv
SO_2	200 ppmv
Operating Data:	
Remaining Plant Life	15 years
Annual Operating Hours	6,500 hours
Annual Operating Cost	$557,000/year

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[a] per combustor.

[b] All emissions are dry, corrected to 7 percent O_2.

room. It is estimated that installations of the monitors can be completed during a schedule outage with no unscheduled downtime.

7.2.3.2 Environmental Performance. The modifications will provide verification of proper combustion operation. No changes in emissions from baseline are expected.

7.2.3.3 Good Combustion Control Costs. The capital costs of the modification are presented in Table 7.2-2. Total capital costs are estimated to be $117,000. Annual costs are presented in Table 7.2-3. Annualized capital is $15,000 based on a 15-year facility life and a 10 percent interest rate. Total annualized costs are $84,000 per year, including annualized capital and O&M.

7.2.4 Moderate Particulate Control

7.2.4.1 Description of Modifications. To achieve moderate PM control (0.08 gr/dscf) will require the additional of a new ESP with 2,050 square feet of plate area. This ESP is sized to handle the flue gas from both combustors. It is assumed that there is sufficient space beyond the existing stack to locate the ESP, and that access/congestion constraints are moderate. Forty-five feet of flue gas ducting would be required to connect the water quench to the ESP and connect the ESP outlet to a new stack. Besides a new stack, a new I.D. fan is included to handle the additional pressure drop of the new ESP and ductwork. In addition, cost for an opacity monitor and data reduction system is included. The opacity monitor is to be located at the outlet of the ESP. Figure 7.2-2 also shows the location of the ESP, ductwork, new I.D. fan, and new stack.

Downtime will affect both combustors at once and is estimated at one month for ductwork tie-ins.

7.2.4.2 Environmental Performance. Particulate matter emissions will be reduced from baseline levels of 0.15 gr/dscf to 0.08 gr/dscf. This additional fly ash recovery will add 9 tons/year (dry) to the solid waste disposal requirements. CDD/CDF and acid gas emissions are not affected by this modification.

7.2.4.3 Costs. Capital cost requirements for moderate particulate control are presented in Table 7.2-4. The major cost item is the particulate control equipment. Total capital cost is estimated to be $580,000. This

TABLE 7.2-2. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS
(Two units at 25 tpd each)

Item		Costs ($1,000)
DIRECT COSTS:		
Oxygen and CO Monitors with Readouts and Integrators		90
	Total	90
Indirect Costs and Contingency		27
TOTAL CAPITAL COSTS		117
DOWNTIME COST		0
ANNUALIZED CAPITAL COSTS		15

TABLE 7.2-3. PLANT ANNUAL COST OF COMBUSTION MODIFICATIONS
(Two units at 25 tpd each)

Item	Costs ($1,000)
DIRECT COSTS:	
Maintenance labor	20
Maintenance Materials	20
Operating Labor	0
Total	40
INDIRECT COSTS:	
Overhead	24
Taxes, Insurance, and Administration	5
Capital Recovery and Downtime	15
Total	44
TOTAL ANNUALIZED COST	84

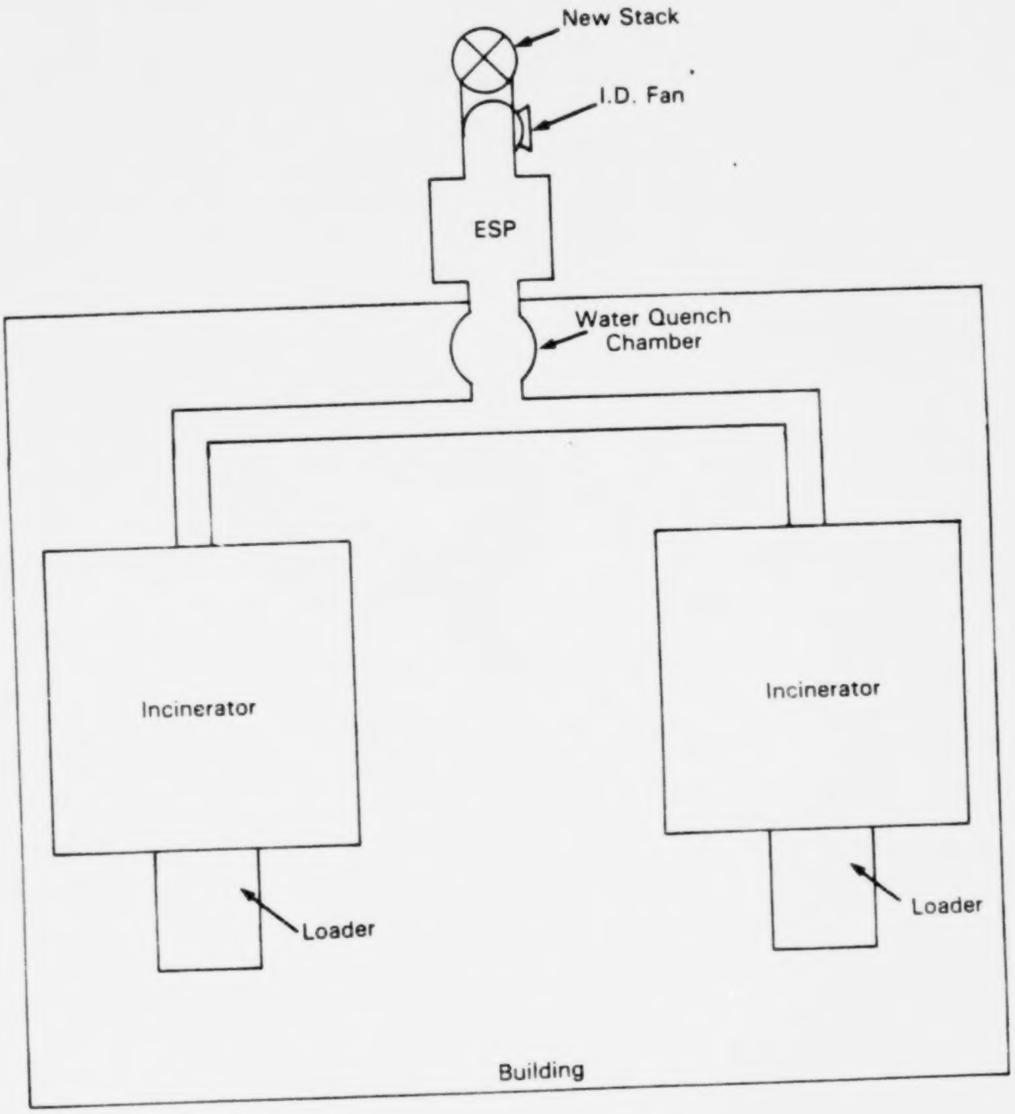

Figure 7.2-2. Plot Plan of Temperature and Particulate Control Equipment

TABLE 7.2-4 PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS
(Two units of 25 tpd each)

Item	Costs ($1,000)		
	Moderate PM Control[b]	Good PM Control	Best PM Control
DIRECT COSTS:			
Particulate Control[a]			
Equipment	226	302	562
Access/Congestion Cost	56	75	141
Temperature Control			
Equipment	0	0	0
Access/Congestion Costs	0	0	0
New Flue Gas Ducting[a]			
Ducting Costs	9	9	9
Access/Congestion Cost	3	3	3
Other Equipment			
Fan	35	35	35
Stack	100	100	100
Demolition/Relocation	0	0	0
Total	429	524	850
Indirect Costs and Contingencies	90	90	90
Monitoring Equipment	60	60	60
TOTAL CAPITAL COST	580	675	1,000
DOWNTIME COSTS	19	19	19
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	79	92	135

[a] Turnkey

[b] Moderate PM control is 0.08 gr/dscf at 7 percent O_2.

cost includes purchase equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume moderate APCD congestion level.

Annual costs are presented in Table 7.2-5 and are dominated by capital recovery and downtime. Indirect annual costs including capital recovery and downtime are estimated to be $112,000 per year. Direct operating and maintenance costs are estimated at $31,000 per year. Thus, total annualized cost for moderate PM control is estimated at $144,000 per year.

7.2.5 Good Particulate Control

7.2.5.1 Description of Modifications. To achieve good PM control (0.05 gr/dscf) will require the addition of a new ESP with 5,590 square feet of plate area. This ESP is sized to handle the flue gas from both combustors. It is assumed that there is sufficient space beyond the existing stack to locate the ESP, and that access/congestion constraints are moderate. Approximately 45 feet of flue gas ducting would be required to connect the water quench chamber to the ESP and connect the ESP outlet to a new stack. Besides a new stack, a new I.D. fan is included to handle the additional pressure drop of the new ESP and ductwork. In addition, cost for an opacity monitor and data reduction system is included. The opacity monitor is to be located at the outlet of the ESP. Figure 7.2-2 also shows the location of the ESP, ductwork, new I.D. fan, and new stack.

Downtime will affect both combustors at once and is estimated at one month for ductwork tie-ins.

7.2.5.2 Environmental Performance. Particulate matter emissions will be reduced from baseline levels of 0.15 gr/dscf to 0.05 gr/dscf. This additional fly ash recovery will add 13 tons/year (dry) to the solid waste disposal requirements. CDD/CDF and acid gas emissions are not affected by this modification.

7.2.4.3 Costs. Capital cost requirements for good particulate control are presented in Table 7.2-4. The major cost item is the particulate control equipment. Total capital cost is estimated to be $524,000. This figure includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion level.

TABLE 7.2-5 PLANT ANNUAL COST FOR NEW PARTICULATE MATTER CONTROLS
(Two units of 25 tpd each)

Item	Costs		
	Moderate PM Control[a]	Good PM Control	Best PM Control
DIRECT COSTS:			
Operating Labor	10	10	10
Supervision	1	1	1
Maintenance Labor	5	5	5
Maintenance Materials	4	5	8
Electricity	1	2	3
Water	0	0	0
Waste Disposal	0	0	0
Monitors	8	8	8
Total	29	31	34
INDIRECT COSTS:			
Overhead	12	13	15
Taxes, Insurance, and Administration	21	25	38
Capital Recovery and Downtime	79	92	135
Total	112	129	188
TOTAL ANNUALIZED COST	141	160	221

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[a] Moderate PM control is 0.08 gr/dscf at 7 percent O_2

Annual costs are presented in Table 7.2-5 and are dominated by annualized capital recovery and downtime. Indirect annual costs including capital recovery and downtime are estimated to be $129,000 per year. Direct operating and maintenance costs are estimated at $31,000 per year. Thus, total annualized cost for good PM control is estimated at $160,000 per year.

7.2.6 Best Particulate Control

7.2.6.1 Description of Modifications. To achieve best PM control (0.01 gr/dscf), a single new ESP with approximately 15,900 square feet of collection area will be installed to serve both combustors. The new ESP, ductwork, I.D. fan, and new stack are located as shown in Figure 7.2-2. An opacity monitor is located at the outlet of the new ESP. Approximately 45 feet of new ducting will be required. Downtime will affect both combustors at once and is estimated at 1 month for ductwork tie-ins.

7.2.6.2 Environmental Performance. Particulate matter emissions will be reduced from 0.15 gr/dscf to 0.01 gr/dscf. The additional recovered fly ash will add 19 tons/yr to the site total solid waste disposal requirements. CDD/CDF and acid gas emissions are not affected by this modification.

7.2.6.3 Costs. Capital cost requirements for the best particulate control are presented in Table 7.2-4. Total capital cost is estimated to be $1,000,000. This includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume a moderate APCD congestion level.

Annual costs are presented in Table 7.2-5 and are dominated by annualized capital recovery and downtime. Indirect annual costs are $188,000 per year. Direct operating and maintenance costs are estimated at $34,000 per year. Thus, total annualized cost for best PM control is estimated at $221,000 per year.

7.2.7 Good Acid Acid Gas Control

7.2.7.1 Description of Modifications. For good acid gas control, dry sorbent will be injected into the new ductwork between the water quench chamber and a new fabric filter. The flue gas flow rate at the water quench chamber outlet is 15,500 acfm at 300°F. This temperature reduction is achieved by adding an additional 5 gpm of water in the water quench chamber. New equipment for dry sorbent injection includes one sorbent storage silo, a pneumatic sorbent transport system, one sorbent feed bin, and a pneumatic sorbent injection system. Hydrated lime sorbent will be fed at a calcium-to-acid gas molar ratio of 2:1. At full load, this requires a sorbent injection rate of 57 lb/hr. Approximately 6,460 square feet of fabric filter cloth will be required based on a gross air-to-cloth ratio of 3:1. A new I.D. fan and 70 feet of new ductwork will also be required.

Figure 7.2-3 shows the location of the equipment. Moderate access/congestion levels were assumed for the ductwork and fabric filter. Moderate access/congestion levels were also assumed for the lime receiving, storage, and conveying equipment. New monitoring equipment for SO_2, HCl, and O_2 is also included and is located upstream of the sorbent injection area and also at the outlet of the fabric filter. In addition, an opacity monitor will be located at the outlet of the fabric filter. Downtime is estimated at 1 month for ductwork tie-ins.

7.2.7.2 Environmental Performance. CDD/CDF emissions are expected to be reduced by 75 percent from inlet levels. Acid gas emission reductions are 80 percent for HCl and 40 percent for SO_2, respectively. Emissions of PM are 0.01 gr/dscf. This technology will add 255 tons/year of sorbent and fly ash to the baseline solid waste disposal requirements.

7.2.7.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 7.2-6. Total capital cost is estimated at $1,430,000. Most of the cost is associated with new particulate control. This estimate assumes moderate APCD access/congestion level.

Annual O&M and indirect costs are presented in Table 7.2-7. The major operating cost is monitoring equipment maintenance. The largest annualized cost is annualized capital recovery and downtime. The total annualized costs for the modification are $534,000 per year. Capital and O&M costs are the same for baseline and good combustion conditions since flue gas flow rate and acid gas content are the same for each case.

7.2.8 Best Acid Gas Control

7.2.8.1 Description of Modifications. For best acid gas control, a new spray dryer/fabric filter system will be installed. Lime slurry will be fed to a single spray dryer at a 2.5:1 molar calcium-to-acid gas ratio. Lime will be slurried in sufficient water to cool the flue gas from 450°F to

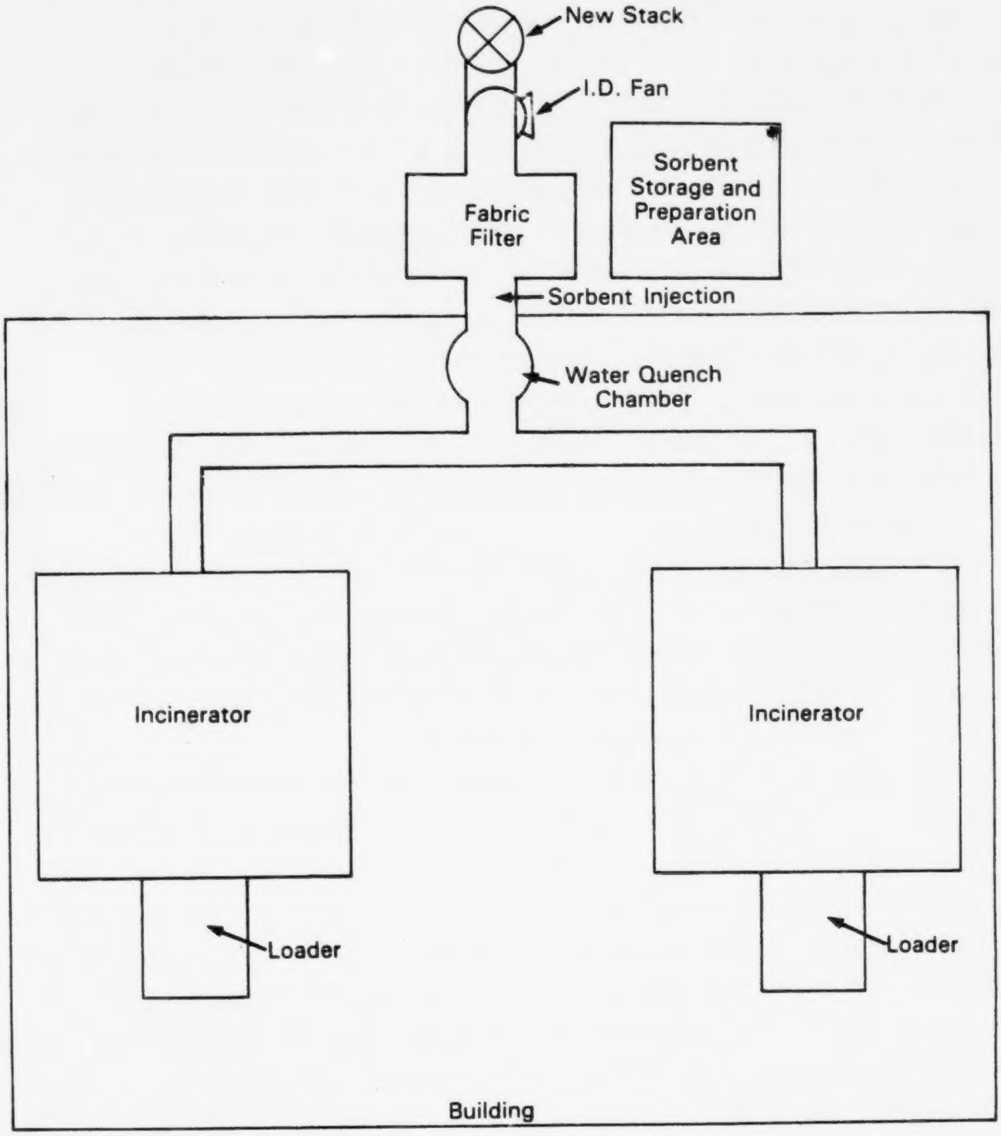

Figure 7.2-3. Plot Plan of Dry Sorbent Injection/Fabric Filter Retrofit Equipment Arrangement

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TABLE 7.2-6. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH FABRIC FILTER (Two units of 25 tpd each)

Item	Costs ($1,000)
DIRECT COSTS:	
Acid Gas Control	
Equipment	158
Access/Congestion Cost[a]	16
Particulate and Temperature Control	
Equipment	267
Access/Congestion Cost	167
New Flue Gas Ducting	
Ducting cost	14
Access/Congestion Cost	4
Other Equipment	
Fan	33
Stacks	59
Demolition/relocation	0
Total	618
Indirect Costs and Contingencies	527
Monitoring Equipment[a]	286
TOTAL CAPITAL COST	1,430
DOWNTIME COST	19
ANNUALIZED CAPITAL RECOVERY	191

[a] Turnkey.

TABLE 7.2-7. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH FABRIC FILTER (Two units at 25 tpd each)

Item	Costs ($1,000)
DIRECT COSTS:	
Operating Labor	39
Supervision	6
Maintenance Labor	16
Maintenance materials[a]	33
Electricity	20
Compressed Air	2
Water	0
Lime	15
Waste Disposal	6
Monitors	107
Total	244
INDIRECT COSTS:	
Overhead	53
Taxes, Insurance, and Administration	46
Capital Recovery and Downtime	191
Total	290
TOTAL ANNUALIZED COST	534

[a] Includes $5,000 for bag replacement.

300°F. Flue gas flow rate at 300°F is 7,750 acfm. A fabric filter with 6,460 square feet of cloth (gross air-to-cloth ratio of 3:1) will be installed following the spray dryer.

This arrangement will require about 100 total feet of new duct, which will connect the water quench chamber and spray dryer/fabric filter to the combustor exit and to a new stack. The proposed equipment layout is illustrated in Figure 7.2-4. This sketch also shows the location of the lime receiving, storage, and slurry area and the location of the waste storage silo. Access and congestion levels are assumed to be moderate for the flue gas ducting, spray dryer/fabric filter and the sorbent preparation and waste silo. New monitoring equipment for HCl, SO_2, O_2 will be installed at both the inlet to the spray dryer and the outlet of the fabric filter. Also, an opacity monitor will be installed at the outlet of the fabric filter. Downtime is expected to be 1 month for ductwork tie-ins.

7.2.8.2 Environmental Performance. CDD/CDF emissions are expected to decrease to 5 ng/dscm. Emissions of particulate matter will be reduced to 0.01 gr/dscf. Acid gases will be reduced 90 percent for SO_2 and 97 percent for HCl.

7.2.8.3 Costs. Capital cost requirements for installing a spray dryer/fabric filter system are presented in Table 7.2-8. Total capital cost is estimated at $3,320,000 for both baseline and good combustion conditions and includes purchased equipment, installation, and indirect costs such as engineering and contingencies. Estimates assume moderate access and congestion.

Annual O&M and indirect costs are presented in Table 7.2-9. The most significant annual costs are maintenance materials including bag replacement and annualized capital recovery and downtime. Total annualized cost of good acid gas control would be $880,000 per year.

7.2.9 Summary of Control Options

7.2.9.1 Description of Control Options. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 7.2-10 summarizes the combustion, particulate, and acid gas control technologies described in Sections 7.2.3 through 7.2.8 that were combined for each of the control options described in

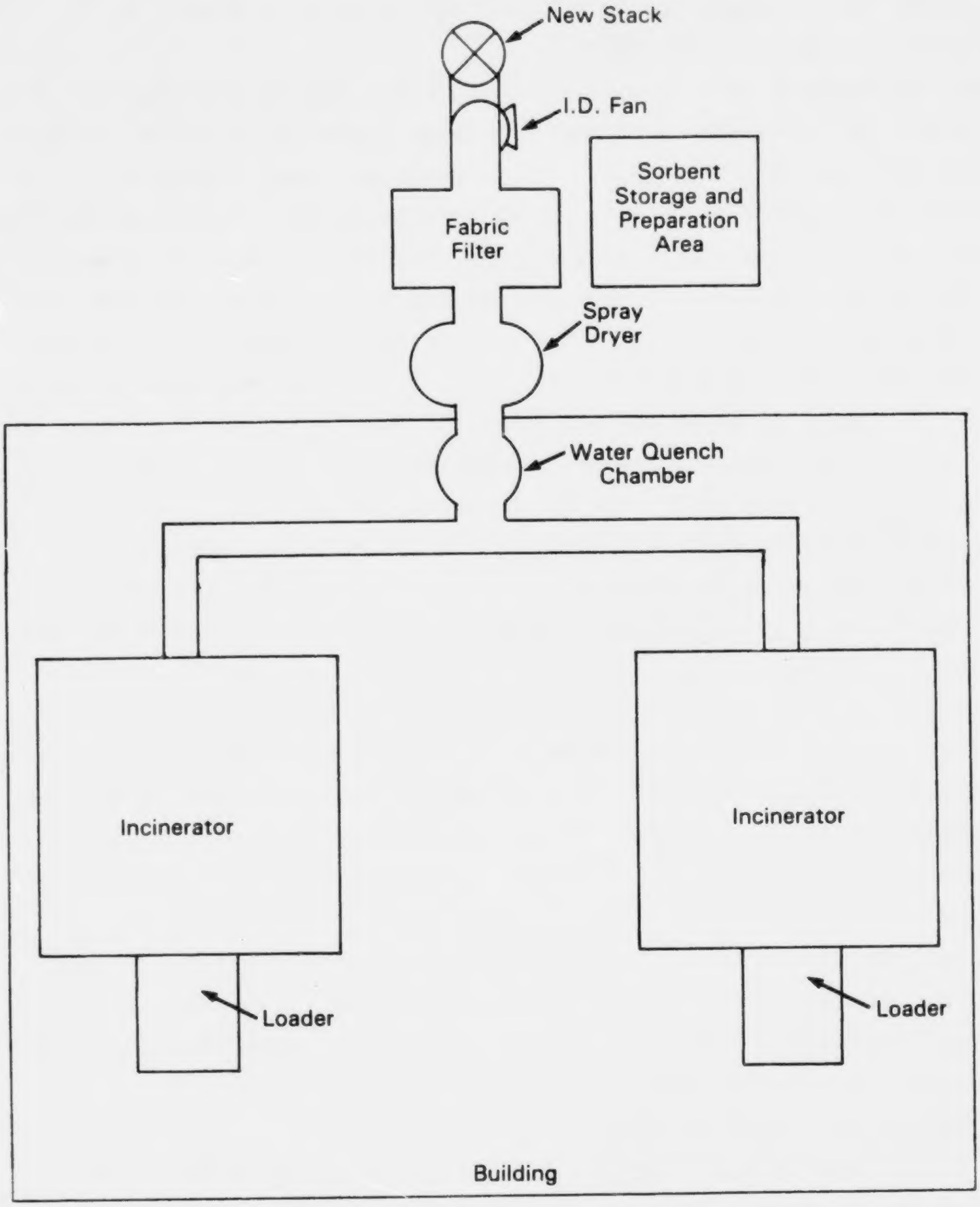

Figure 7.2-4. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement

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TABLE 7.2-8. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units at 25 tpd each)

Item	Costs ($1,000)
DIRECT COSTS:	
Acid Gas and Particulate Control	
Equipment	1,430
Access/Congestion Cost	358
New Flue Gas Ducting	
Ducting cost	21
Access/Congestion Cost	5
Other Equipment	
Fan	35
Stacks	59
Demolition/relocation	0
Total	1,910
Indirect Costs and Contingencies	1,120
Monitoring Equipment[a]	286
TOTAL CAPITAL COST	3,320
DOWNTIME COST	19
ANNUALIZED CAPITAL RECOVERY	439

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[a] Turnkey.

TABLE 7.2-9. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units at 25 tpd each)

Item	Costs ($1,000)
DIRECT COSTS:	
Operating Labor	39
Supervision	6
Maintenance Labor	21
Maintenance materials	42[a]
Electricity	19
Compressed Air	2
Water	0
Lime	12
Waste Disposal	8
Monitors	107
Total	258
INDIRECT COSTS:	
Overhead	62
Taxes, Insurance, and Administration	121
Capital Recovery and Downtime	439
Total	622
TOTAL ANNUALIZED COST	880

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[a] Includes $5,000 for bag replacement.

TABLE 7.2-10. SUMMARY OF CONTROL OPTIONS FOR SMALL MODULAR STARVED-AIR RECIPROCATING GRATE MWC MODEL PLANT

			Particulate Control		Acid Gas Control	
Control Option Description	Combustion Modifications	Temperature Control	New ESP	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion Control						
2. Good PM Control and Combustion Control			X			
3. Best PM Control and Combustion and Temperature Control			X			
4. Good Acid Gas Control, and Best PM Control and Temperature Control		X		X	X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X	X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X		X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X

Section 3.0. It should be noted that since the model plant achieves good combustion at baseline, Options 4 and 5 are identical, and Options 6 and 7 are identical.

7.2.9.2 Environmental Performance. The performance of each control option is summarized in Table 7.2-11. For each pollutant the table presents both the pollutant concentrations and annual emissions. The greatest reductions in acid gases, particulate matter, and CDD/CDF all are achieved with the spray dryer/fabric filter system. The next most effective control for all these pollutants is dry sorbent injection. Both sorbent addition technologies increase the baseline solid waste disposal by about six percent. No combustion modifications were appropriate. Therefore, CO emissions remain unchanged, at 100 ppm, for all control options.

7.2.9.3 Costs. The total annualized cost of each option is presented in Table 7.2-12. The most expensive control option (Option 7) on an annualized basis is the spray dryer/fabric filter installation at $1,000,000. This cost is roughly a factor of 8 higher than the cost for Option 1. Overall, both capital and annualized costs are higher for higher levels of control.

7.2.9.4 Energy Impacts. Table 7.2-13 summarizes the energy impacts associated with the control options. The energy use figures are incremental use. Both the dry sorbent injection with fabric filter and spray dryer with fabric filter consume the most electricity. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and burn the same amount of fuel under baseline and the other control options.

TABLE 7.2-11. ENVIRONMENTAL PERFORMANCE SUMMARY FOR SMALL MODULAR STARVED-AIR RECIPROCATING GRATE MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 25 tpd each)

	Baseline	Option 1	Moderate	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions									
(ng/dscm)	400	400	400	400	400	100	100	5	5
Mg/yr[b]	2.1E-5	2.1E-5	2.1E-5	2.1E-5	2.1E-5	5.3E-6	5.3E-6	2.6E-7	2.6E-7
% Reduction vs. Baseline	--	0	0	0	0	75	75	98.6	98.6
CO Emissions									
(ppmv)	100	100	100	100	100	100	100	100	100
Mg/yr	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
% Reduction vs. Baseline	--	0	0	0	0	0	0	0	0
PM Emissions									
(gr/dscf)	0.15	0.15	0.08	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	18.0	18.0	9.6	6.0	1.2	1.2	1.2	1.2	1.2
% Reduction vs. Baseline	----	0	47	67	93	93	93	93	93
SO_2 Emissions									
(ppmv)	200	200	200	200	200	120	120	19	19
Mg/yr	29.4	29.4	29.4	29.4	29.4	17.6	17.6	2.8	2.8
% Reduction vs. Baseline	--	0	0	0	0	40	40	90.5	90.5
HCl Emissions									
(ppmv)	500	500	500	500	500	100	100	15	15
Mg/yr	40.5	40.5	40.5	40.5	40.5	8.1	8.1	1.2	1.2
% Reduction vs. Baseline	--	0	0	0	0	80	80	97	97
Total Solid Waste									
(tons/day)	15.0	15.0	15.0	15.1	15.1	15.9	15.9	16.2	16.2
Mg/Yr	3,690	3,690	3,690	3,700	3,700	3,920	3,920	3,990	3,990
% Increase vs. Baseline	--	0	0.2	0.3	0.5	6	6	8	8

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[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis.

[b] Mass emission rates are for total plant (both combustors).

TABLE 7.2-12. COST FOR SMALL MODULAR STARVED-AIR RECIPROCATING GRATE MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 25 tpd each)

	Option 1	Moderate[b]	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	117	697	792	1,120	1,430	1,550	3,320	3,440
Downtime Cost	0	19	19	19	19	19	19	19
Annualized Capital and Downtime Cost	15	94	107	150	191	206	439	454
Direct O&M Cost	58	87	89	92	244	302	258	316
Total Annual Cost	124	265	284	345	534	658	880	1,000
Facility Downtime (Months)	0	1	1	1	1	1	1	1
Cost Effectiveness ($/ton MWS)	9.16	19.60	21.00	25.50	39.40	48.60	65.00	73.90
Total Compliance Time (Months)	3	19	19	19	19	19	25	25

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[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

[b] Includes costs for combustion modifications.

TABLE 7.2-13. ENERGY IMPACTS FOR SMALL MODULAR STARVED-AIR COMBUSTOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	20.4	0
3	27.0	0
4	437	0
5	437	0
6	424	0
7	424	0

[a] Increase from baseline consumption.

7.3 REFERENCES

1. Schindler, P., Energy and Environmental Research Corporation, and Emmel, T., Radian Corporation. Trip Report - Retrofit Control Sites Evaluation at the Tuscaloosa Energy Recovery Facility. February 9, 1988.

2. Epner, E., Radian Corporation; Landrum, V., and Schindler, P., Energy and Environmental Research Corporation. Trip Report: Retrofit Control Site Evaluation at the Waxahachie Solid Waste Recovery Plant. March 8, 1988.

8.0 MODULAR EXCESS-AIR COMBUSTORS

The population of modular excess-air municipal waste combustors (MWC's) consists of 10 facilities. These plants have individual combustor capacities ranging in size from 8 to 120 tpd. Several manufacturers supply modular excess-air designs, including Vicon/Enercon, Cadoux, Sigoure Freres, and Olivine. The Vicon/Enercon facilities comprise the largest share of the population in terms of overall capacity (1200 tpd). A complete description of the Vicon/Enercon design is given in the case study in Section 8.1.

The Cadoux design includes hydraulic forks which load the waste into a refractory-lined primary chamber where burning takes place on oscillating grates. Underfire air is supplied beneath the grates. Combustion gases are burned out in a refractory-lined secondary chamber and then flow to a waste heat boiler. Temperatures in the secondary chamber reportedly approach 2000°F. Approximately 33 percent of the total air is added beneath the grate and the remainder is supplied in the secondary post-combustion chamber. They system reportedly operates at 15 percent excess O_2 (approximately 250 percent excess-air) at the boiler outlet. Typical boiler exit gas temperatures range from 450 to 500°F.

The Sigoure Freres system is also a two-chamber design. Waste is burned in the primary chamber on a revolving angular hearth which is covered by a grate. Ten automatic pokers stoke the burning waste bed on the hearth as it revolves. Approximately 80 percent of total combustion air is supplied in the primary chamber as undergrate air and through sidewall overfire air nozzles. Combustion gases flow to a cyclonic post-combustion chamber where burnout is completed, and then to a waste heat boiler. The system reportedly operates at 12 to 14 percent excess O_2 (150 to 200 percent excess-air).

TABLE 8.0-1. EXISTING MODULAR EXCESS-AIR COMBUSTORS

Plant/Location	Manufacturer	No. of Units	Unit Size (tpd)	Year of Start-up	Air Pollution Control Device
Sitka, AK	Sigoure Freres	2	12.5	1985	None
Wilmington, DE	Vicon/Enercon	5	120	1987	Electrostatic Precipitator
Mayport NAS, FL	NA[a]	1	48	1978	Cyclone
Pittsfield, MA	Vicon/Enercon	3	120	1981	Electrified Gravel Bed
Aroostook, ME	Olivine	1	50	1982	None
Alexandria, MN	Cadoux	1	100	86	Electrostatic Precipitator
Pascagoula, MI	Sigoure Freres	2	75	1985	Electrostatic Precipitator
Cleburne, TX	Cadoux	3	38	1986	Electrostatic Precipitator
Rutland, VT	Vicon/Enercon	2	110	1987	Electrostatic Precipitator
Nottingham, NH	NA	1	8	1972	None

[a] NA = Information not available.

8.1 INTRODUCTION

This section presents the case study results for a mass burn modular excess-air MWC. Section 8.1.1 presents a description of the plant located in Pittsfield, MA, which was visited to gather information for model development. Section 8.1.2 presents a description of the model plant. Sections 8.1.3 through 8.1.6 detail the retrofit modifications, estimated performance, and costs associated with each control option. Section 8.1.7 presents a summary of the control options, which are discussed in more detail in Section 3.0 of this report.

8.1.1 Description of the Pittsfield, MA Plant[1]

The Pittsfield waste-to-energy plant began commercial operation in 1981. The plant handles all the waste generated in the Pittsfield community and accepts waste from an additional six towns in the surrounding area. The facility occupies a 5-acre site and has three modular excess air refractory-wall combustors. Each combustor has a rated capacity of 120 tons of municipal solid waste (MSW) per day. The combustion system is an Enercon multi-chamber design with flue gas recirculation (FGR). Vicon is the licence of Enercon technology. Figure 8.1-1 illustrates the Pittsfield plant layout, including the three combustor trains which are integrated with two waste heat boilers. Two waste heat recovery boilers are used to generate steam for sale to a nearby paper manufacturer (Crane Company). Cross-connected breechings and dampers allow operation of any two of the three combustors with the two waste heat boilers. Air pollutant emissions are controlled by the unique combustion process and by an electrified granular bed (EGB), supplied by Combustion Power Company, Inc. Table 8.1-1 presents Pittsfield plant design data.

Waste is delivered to the plant where it can be dumped into a storage pit or onto a tipping floor. The plant has three days waste storage capacity. Transfer stations are located at the side of the plant where individuals are permitted to dump waste. The transfer point allows large haulers to have priority in accessing the pit and the tipping floor. A crane transfers MSW from the pit to the tipping floor where a front-end loader charges the combustors.

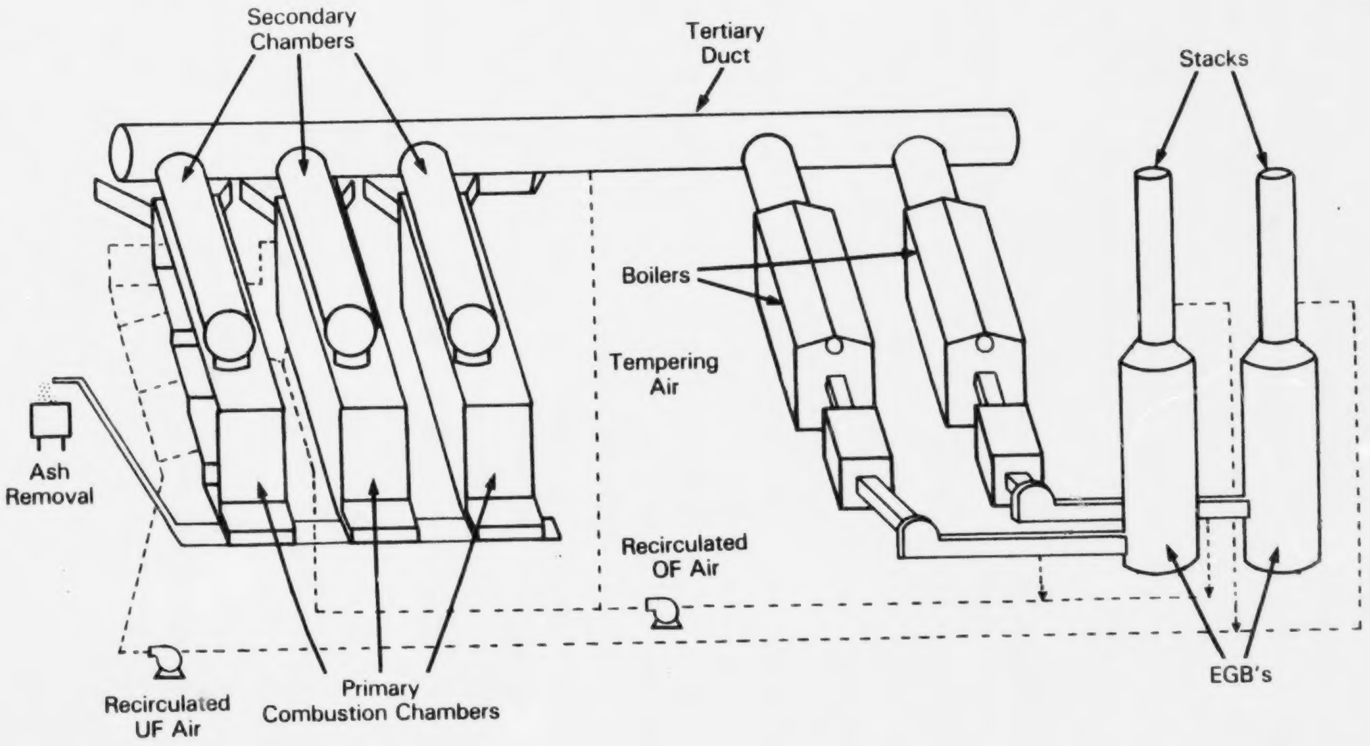


Figure 8.1-1. Equipment Train at Pittsfield

TABLE 8.1-1. PITTSFIELD, MASSACHUSETTS DESIGN DATA

Combustor:	
Type	Modular Excess-air
Manufacturer	Enercon/Vicon
Number of Combustors	3
Combustor Unit Capacity	120 tpd each
Emission Controls:	
Type	Electrified Granular Bed (EGB)
Manufacturer	Combustion Power Co., Inc.
Number of EGB's	2
Operating Temperature	475^{0}F
Particulate Emissions	0.04 gr/dscf at 12% CO_2
Gas Flow (each EGB) at 475^{0}F	25,000 acfm
Gas Velocity	1.5 to 2.5 ft/s

In addition to burning MSW and commercial waste, the plant also fires 12 tpd of sludge from the steam customer's pulping operation. The sludge dewatering press is located in the same building as the waste-fired combustors. The dewatered sludge is normally 40 percent moisture by weight (5 dry tpd).

The Pittsfield plant operates two of the waste-fired units on a 24-hour/day, 7-day/week schedule. The third unit is kept on standby. Complete plant shutdown is scheduled for two weeks every July to coincide with a scheduled shutdown of the steam customer. The waste-fired plant reports an average availability of 90 percent (based on two units), with only 8 percent scheduled down time. Most of the scheduled down time occurs during the summer outage. Each of the boilers is brought off line every 5 months for a 24-hour scheduled cleaning. A gas/oil-fired boiler is located on site to handle load swings during normal operation.

8.1.1.1 Combustor Design and Operation. Figure 8.1-2 shows a schematic of a typical Enercon/Vicon design. A front-end loader delivers waste from the tipping floor to individual combustor charging hoppers (dimensions 8′ by 6′ by 5′) at a 10-minute charging interval. The waste is charged to the primary combustion chamber by a hydraulic ram which extends after the top hopper door closes and the fire door opens. The two operating combustors (240 tpd combined capacity) normally process a total of 220 to 230 tpd. Reduced capacities are reported to be due in part to a desire to achieve good waste burnout. Waste retention time in the primary chamber is approximately three hours.

The primary combustion chamber is refractory-lined and contains five hearths. Each hearth is ten feet in length. Figure 8.1-2 shows six hearths, which is typical of other Enercon/Vicon designs. Waste is moved through the chamber on the stepped hearths by the action of water-cooled transfer rams. The stroke of the transfer rams is five feet.

The primary chamber contains a number of points of combustion air injection (discussed below). The temperature in the primary chamber is nominally maintained at 1800 to 1900°F. There is no additional air injected into the secondary chamber. The temperature is verified by a thermocouple located in the secondary chamber. A Thermox continuous O_2 analyzer is located at the exit of the secondary chamber. A signal from the O_2 analyzer

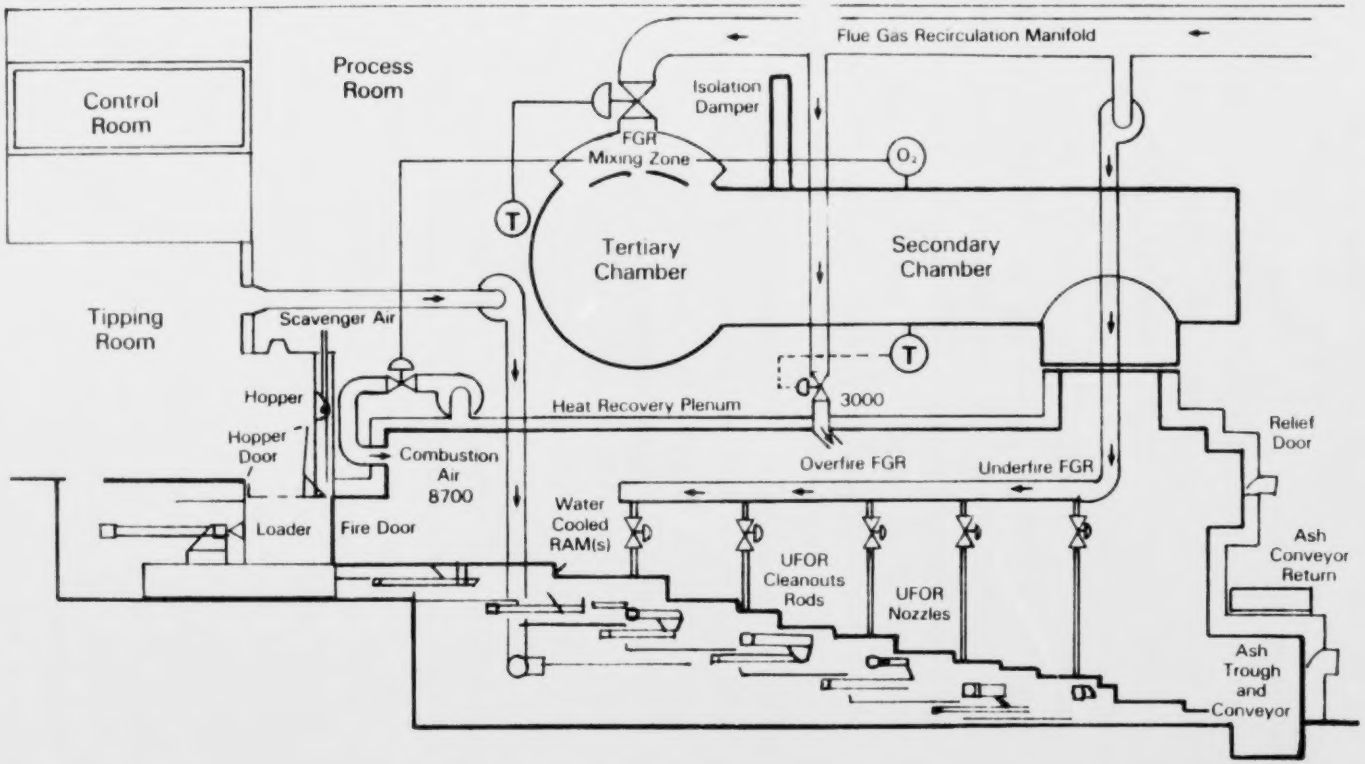


Figure 8.1-2. Typical Vicon/Enercon Module.

automatically adjusts the rate of one of the four sources of air in the primary chamber. Excess O_2 levels are maintained at approximately 7 percent during normal operation by this control loop.

The secondary chamber flue gases from each combustor manifold into a common tertiary duct where combustion is completed. Recirculated flue gas is injected into the tertiary chamber as tempering air to control the temperature of the gases entering the waste heat boilers to 1400^0F.

The waste heat boilers were manufactured by Bigelow. Design steam production rates per boiler are 33,000 pounds per hour of 180 psig steam at 480^0F. No condensate is returned from the steam customer, so water treatment is necessary for 100 percent make-up water. The flue gases exit the boiler and enter the flue gas cleaning equipment. The induced draft fan is located upstream of the flue gas treatment equipment (downstream of the boiler) and is designed to handle a dirty gas stream.

Combustion Air Flows and Controls. The Enercon design operates in an excess air mode and employs FGR to maintain desired temperatures and flow rates. Air flow is controlled in response to signals from temperature and oxygen readings in various portions of the combustor.

There are four air supplies to the primary combustion chamber: (1) scavenger air, (2) recirculated underfire (UF) air, (3) clean overfire (OF) air, and (4) recirculated OF air. Scavenger air is drawn from the pit and tipping floor and enters the combustion chamber through gaps in the transfer rams. It provides odor control in the pit area and cooling air for the transfer rams. The scavenger air is not significantly pressurized. Recirculated UF air is the main source of UF air on a volume basis. It is drawn from a point in the stack and supplied through individual ducts beneath the five hearths. Each of these points of air supply can be individually controlled by manually-operated dampers.

Clean OF air is supplied through a number of ports at the head of the primary chamber above the charging hearth. This air is preheated to a temperature of 150 to 180^0F by drawing it through a shroud surrounding the primary chamber. This type of air preheat system provides control of heat loss from the primary chamber. The flow rate of the clean OF air is automatically adjusted in response to a signal from the O_2 sensor located at the exit of the secondary chamber. This is the only point of oxygen monitoring in the system. The set point for excess oxygen level is normally seven percent.

Recirculated flue gas is routed from the ducting at the boiler exit (prior to flue gas cleaning) and injected through five 8-inch diameter ports in the roof of the primary chamber. The FGR temperature is typically 400 to 450°F, and the flow rate is automatically adjusted in response to the temperature in the secondary chamber. This flow rate is modulated to maintain the desired secondary chamber temperature (1800 to 1900°F). Although control of furnace temperature is achieved by varying air and FGR flow rates, these gas streams are not directly measured. However, under normal operating conditions the following air flows were reported as measured during testing:

Recirculated UF air - 1600 scfm
Clean OF air - 8700 scfm
Recirculated OF air - 3000 scfm

Scavenger air was not measured.

As stated above, no additional oxidizer is added in the secondary combustion chamber. However, an additional supply of FGR (termed "tempering air") is injected in the tertiary chamber to maintain the desired boiler inlet temperature (1400°F). The rate of tempering air is controlled based on the temperature set point at the boiler inlet.

Start-up/Shutdown Procedures. Each combustor has a fuel oil burner located in the primary combustion chamber which can be used for preheat during start-up. Under normal operation, MSW is not fired until a temperature of 1400°F is attained in the secondary combustion chamber. Generally, wood pallets are charged to the combustor until the required combustion temperature is achieved, whereupon the operator begins charging MSW. During a scheduled shutdown, wood is fed to the combustors until MSW is cleared from the primary chamber. The continuous operation of the combustors results in few scheduled start-ups and shutdowns.

Residue. The bottom ash drops from the last hearth into a water quench pit which also serves as a combustor seal. Ash is conveyed to a holding bin by a drag chain conveyer, then hauled to the landfill. Dry weight reduction is reported to be 75 percent. Volume reduction is reported to be 88 to 90 percent. A limited amount of metal separation takes place prior to combustion (amounting to approximately 1.5 percent of the waste stream).

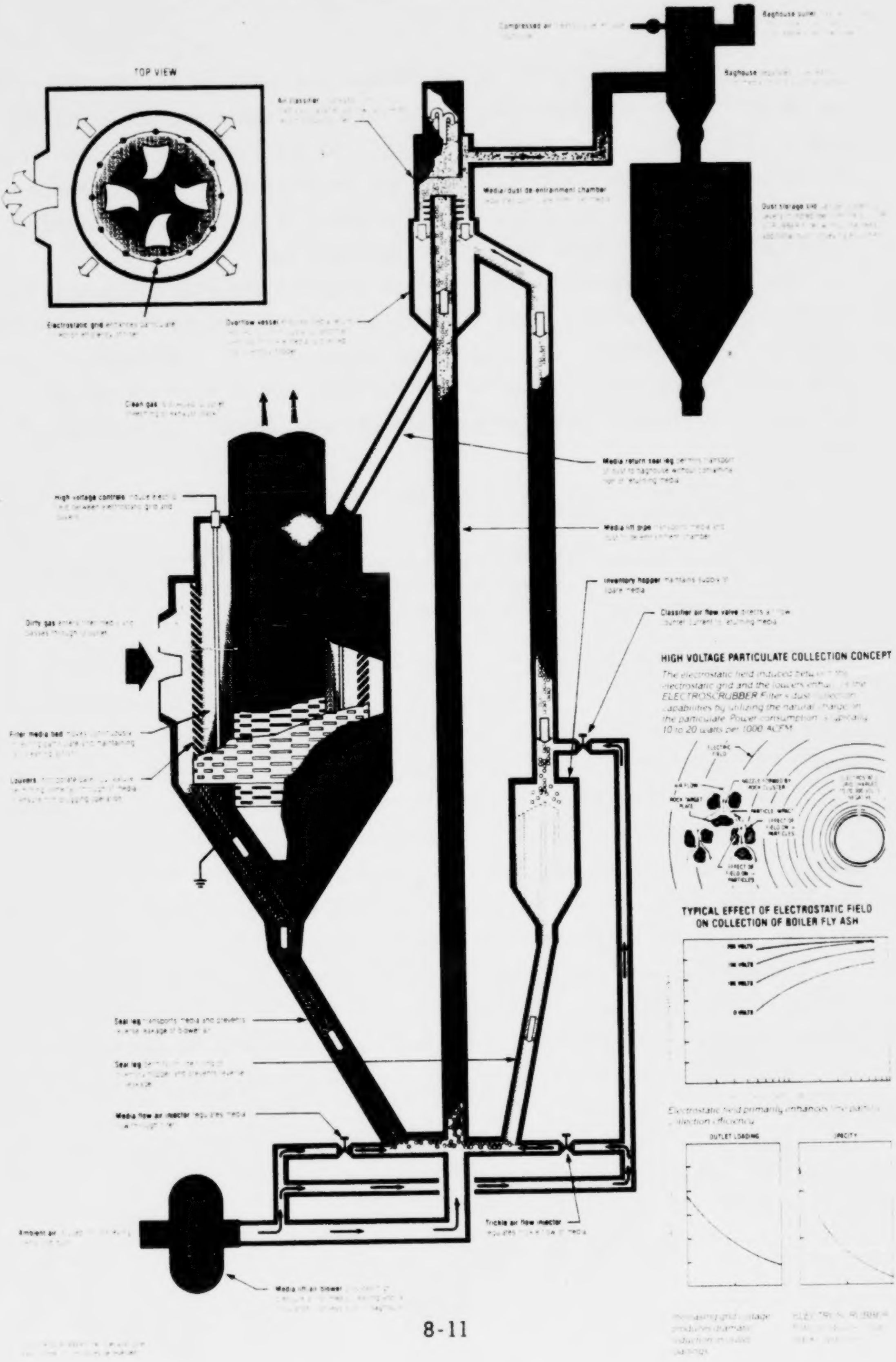
8.1.1.2 Emission Control System Design and Operation. Particulate emissions are controlled by two EGB's. According to literature supplied by the manufacturer to the plant, this is the only MSW facility in the U.S. using this type of control device. Test results from 1986 show that the EGB is reducing PM emission rates to about 0.039 gr/dscf corrected to 12 percent CO_2. No inlet PM data are available.

The EGB's at Pittsfield are mounted on the roof. Figure 8.1-3 shows a schematic of an EGB. The EGB consists of a vessel containing two concentric, louvered cylindrical tubes. The annular space between the tubes is filled with pea-sized gravel media. Dirty gas enters the EGB through the side-mounted breeching, is distributed tot he inner cylinder and passes to the filter media by the plenum section. Flow rates are 25,000 acfm (per EGB) at 475°F. The gas passes through the filter at velocities of 100 to 150 feet per minute. Particulate matter is removed from the gas stream by impact with the gravel media. Clean gas exits to the atmosphere through the stack, which is mounted on top of the filter unit. Fly ash and gravel are separated in the de-entrainment zone. Cleaned gravel is readmitted to the main vessel, and the fly ash is collected in a bag filter.

The filter media is continuously moved downward at a rate of 6 to 10 feet per hour. This rate is regulated by a media lift blower. This moving bed of gravel filter media provides the EGB with the capability for self cleaning, continuous operation. Also, the tumbling action of the filter media, in contact with the louvers, prevents any bridging or buildup of PM on the louvers.

The primary collection phenomenon is impaction - both classical inertial impaction and electrostatically-assisted impaction. An electrostatic grid, configures in the form of a cage, is positioned within the filter media cavity. High voltages applied to the grid produce an electric field between the grid and the louvers. During normal operation, voltage is maintained at 32 KV.

Figure 8.1-3. Electrified Gravel Bed


TOP VIEW
Electrostatic grid enhances particulate collection efficiency of filter
Overflow vessel
Clean gas
High voltage controls induce electric field between electrostatic grid and louvers
Dirty gas enters filter media and passes through louvers
Filter media bed
Louvers
Seal leg transports media and prevents reverse leakage of blower air
Seal leg
Media flow air injector
Ambient air
Media lift air blower
Air classifier
Media/dust de-entrainment chamber
Compressed air
Baghouse outlet
Baghouse
Dust storage silo
Media return seal leg
Media lift pipe
Inventory hopper maintains supply of spare media
Classifier air flow valve directs air flow counter current to returning media
Trickle air flow injector
HIGH VOLTAGE PARTICULATE COLLECTION CONCEPT
The electrostatic field induced between the electrostatic grid and the louvers enhances the ELECTROSCRUBBER Filter's dust collection capabilities by utilizing the natural charge on the particulate. Power consumption is typically 10 to 20 watts per 1000 ACFM.
ELECTRIC FIELD
AIR FLOW
NOZZLE FORMED BY ROCK CLUSTER
ROCK TARGET PLATE
PARTICLE IMPACT
EFFECT OF FIELD ON PARTICLES
TYPICAL EFFECT OF ELECTROSTATIC FIELD ON COLLECTION OF BOILER FLY ASH
0 VOLTS
Electrostatic field primarily enhances fine particle collection efficiency
OUTLET LOADING
OPACITY
Increasing grid voltage produces dramatic reduction in outlet loadings
ELECTROSCRUBBER

The electrostatic field induced between the grid and the louvers raises the PM collection efficiency due to the fact that small fly ash particles have a slight positive or negative charge. As the particles migrate through the filter media, the electrical field either attracts or repels them, depending on charge. In either case, the particle is propelled towards pieces of the gravel media for capture by impaction.

The facility provided a report which assessed the EGB, along with the possibility of retrofitting the facility with an electrostatic precipitator (ESP) or fabric filter. This report was prepared by an independent contractor in response to problems the facility had in maintaining EGB voltages. The report lists two possible reasons for EGB voltage drops. These are:

- interference in feedback signals caused by variable-speed drives on the induced draft fans, and
- insufficient size of transformer/rectifier sets to accommodate larger current flows caused by varying resistivity and concentrations of fly ash in the bed.

8.1.2 Description of the Model Plant

8.1.2.1 Combustor Design and Operation. There are several distinct modular MWC system designs that operate in an excess-air mode (Enercon/Vicon, Cadoux, Sigoure Freres). Due to the variance in these designs, no single model plant can adequately represent all existing facilities. The largest and most prevalent of the excess-air modular systems is the Enercon/Vicon design. There are currently three facilities operating in the U.S. using Enercon/Vicon technology. The model plant represents a typical facility of this design; model plant data are shown in Table 8.1-2.

The model plant consists of two units, each with a rated capacity of 100 tpd. Both units burn 100 percent municipal solid waste, 24-hours/day, 7-days/week. Each module has both primary and secondary combustion chambers which manifold into a single tertiary duct where burning is completed prior to the flue gases entering a waste heat boiler. The boiler reduces the flue gas temperatures from $1400^{\circ}F$ to $450^{\circ}F$ before entering the air pollution control equipment.

TABLE 8.1-2. MODEL PLANT BASELINE DATA FOR MODULAR EXCESS-AIR COMBUSTOR

Combustor:	
Type	- Modular Excess-air
Number of Combustors	- 2
Combustor Unit Capacity	- 100 tpd each
Plant Capacity	- 200 tpd
Emission Controls:	
Type	- Electrostatic Precipitator
Number of ESP's	- 1
Number of Fields	- 2
Inlet Temperature	- 450^{0}F
Collection Efficiency	- 97.5 percent
Gas Flow	- 39,000 acfm
Total Plate Area	- 11,500 ft^2
SCA at 39,000 acfm and 450^{0}F	- 295
Emissions:[a]	
CDD/CDF (tetra-octa)	- 200 ng/dscm
PM (stack)	- 0.05 gr/dscf[b]
CO	- 50 ppmv
HCl	- 500 ppmv
SO_2	- 200 ppmv
Stack Parameters:	
Height	- 70 ft
Diameter	- 5.5 ft
Operating Data:	
Remaining Plant Life	- $\geq$ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $1,300,000/year

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[a] All emissions are dry, corrected to 7 percent 0_2. Standard and Normal conditions are both 70^{0}F and 1 atmosphere.

[b] Inlet PM emissions to the ESP are 2.0 gr/dscf at 7 percent 0_2.

Fuel feeding and combustion air supplies are assumed to be identical to those at Pittsfield, as described above. Excess air levels at the boiler outlet are assumed to be 50 percent. Flue gas flow rates are approximately 19,100 dscfm at the boiler exit. It is assumed that a CO monitor is in place along with the O_2 monitor at the secondary chamber exit. Temperatures are measured at the exit of the primary and secondary chambers, and at the boiler inlet and outlet. An auxiliary fuel burner is located in the primary combustion chamber for use during process start-up and during episodes of low temperature.

8.1.2.2 Emission Control System Design and Operation. As previously mentioned in the description of the Pittsfield plant, the EGB control system is unique amount MSW facilities. As shown in Table 8.0-1, most excess-air combustors have electrostatic precipitators for particulate matter control. Therefore, the model plant is equipped with a single 2-field ESP controlling emissions to 0.05 gr/dscf at 7 percent O_2. Since both combustors are ducted to a single boiler and ESP, a single stack is also assumed. The model plant ID fan is located downstream of the ESP, since this is more common than the upstream location used at Pittsfield. A plot plan of the model plant is shown in Figure 8.1-4.

8.1.2.3 Environmental Baseline. Table 8.1-2 also presents baseline emissions data for the model plant. Baseline uncontrolled emissions are established for the model plant using the measured data from a parametric testing program carried out at Pittsfield. Based on these measured emissions, baseline uncontrolled CDD/CDF emissions are assumed to be 200 ng/dscm. Uncontrolled emissions of CO are 50 ppmv.

No uncontrolled PM data are available for a facility of this design. Therefore, a value of 2.0 gr/dscf is assumed for the model by analogy with other excess-air systems. Uncontrolled HCl and SO_2 emissions are assumed to be 500 ppmv and 200 ppmv, respectively. All emissions are corrected to 7 percent O_2. The combustion process is assumed to reduce incoming waste 90 percent by volume and 70 percent by weight.

It is important to note that this model plant configuration represents the Enercon/Vicon design, and that other modular excess-air designs are

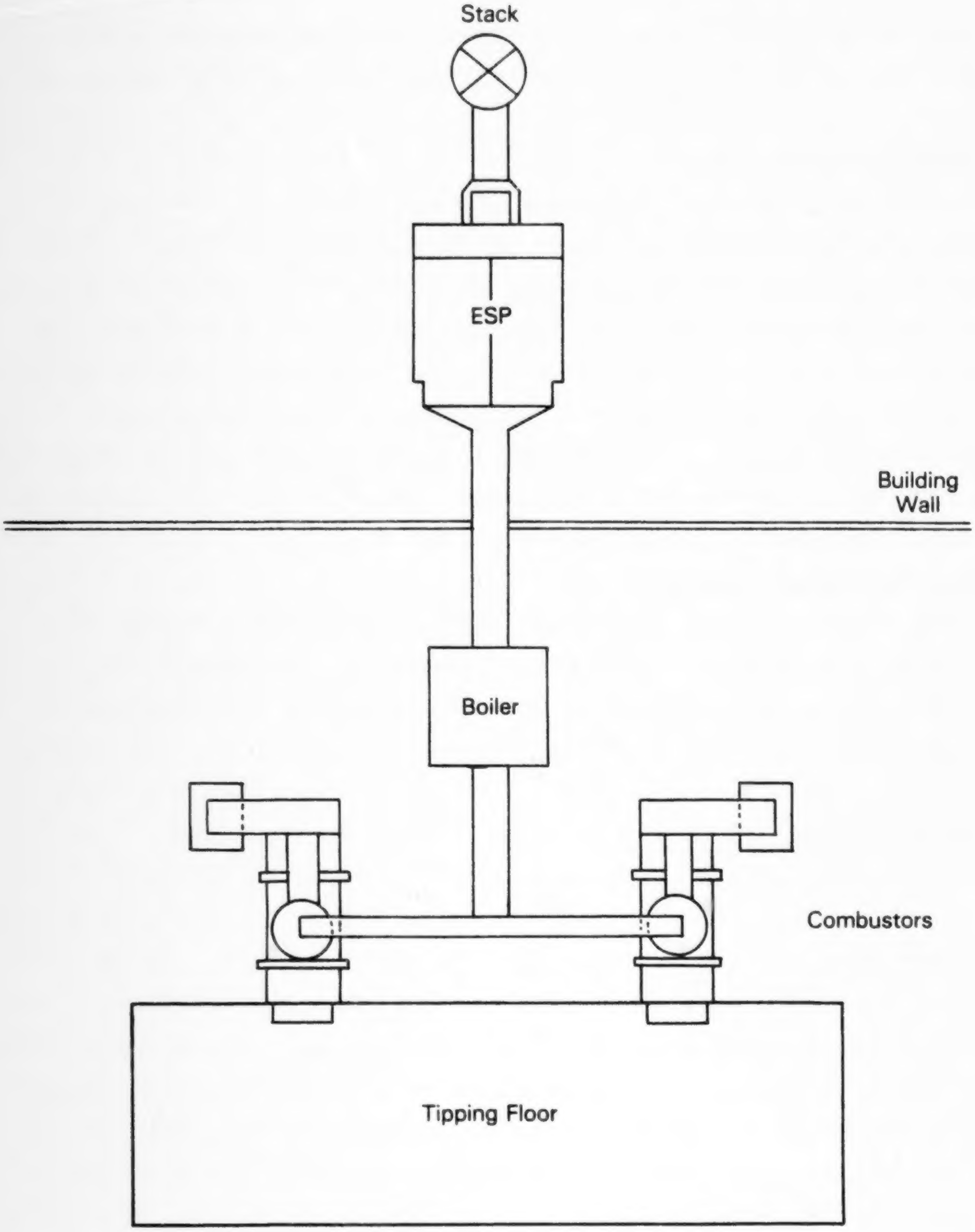

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Figure 8.1-4. Plot Plan of Model Plant

considerably different in configuration. Thus, baseline emission values established for the model may not be appropriate for other model excess-air MWC's.

8.1.3 Good Combustion Control

The model plant has good combustion practices in place. This is verified by the low uncontrolled levels of CDD/CDF and CO emissions. Under normal operating conditions the combustor achieves 1800^{0}F, and good mixing is in place. Monitoring of temperature, oxygen, and CO is also in place. Due to adequate heat removal through the boiler, the exhaust gas temperature is 450^{0}F. As a result, there is no need for further flue gas temperature reduction prior to the air pollution control equipment, and the potential for formation of CDD/CDF in the ESP is minimized. Based on this assessment there are no combustion retrofits required for the model plant.

8.1.4 Best Particulate Control

The ESP in place on the model plant reduces PM by 97.5 percent, from 2.0 gr/dscf to 0.05 gr/dscf corrected to 7 percent O_2. Therefore, the baseline PM emission rate is equal to the rate identified with good control (0.05 gr/dscf), and no plant modifications will be required for this control level.

8.1.4.1 Description of Modifications. To achieve best particulate matter control (0.01 gr/dscf emission rate) will require an ESP with 16,500 square feet of collection area. Therefore, an additional 5,000 square feet will be added to the model plant ESP. The additional area will be installed as a separate single-field ESP in series with the existing ESP. Fifty feet of new duct and a new ID fan will be required. The existing stack will continue to be used. A plot plan of the proposed equipment arrangement is shown in Figure 8.1-5. No new monitoring equipment will be required. Downtime will affect both combustors at once and is estimated at one month for ductwork tie-in.

8.1.4.2 Environmental Performance. Particulate matter emissions will be reduced from 0.05 gr/dscf to 0.01 gr/dscf. The increased fly ash recovery will add 26 tons per year to the baseline solid waste disposal requirements for the plant.

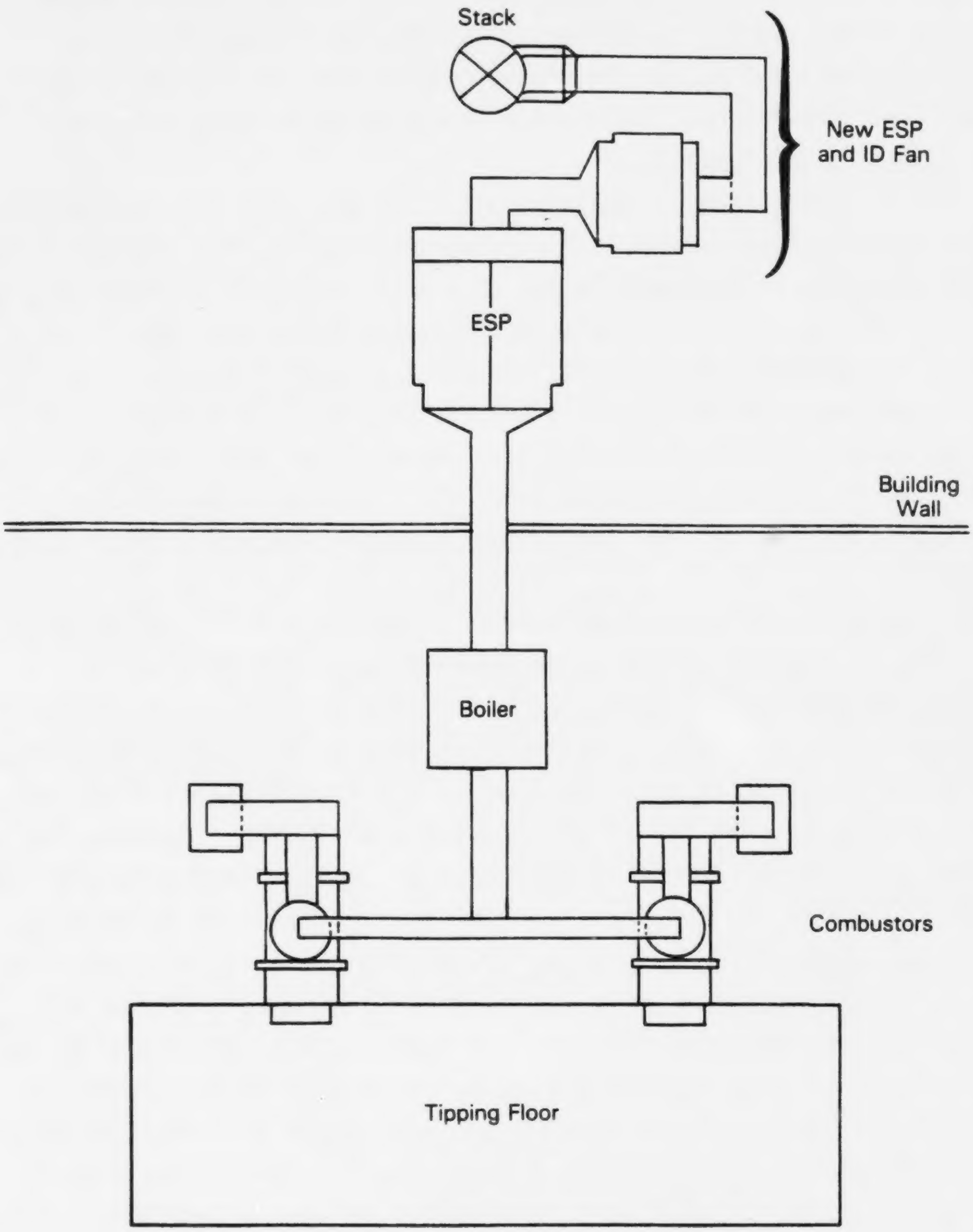

Figure 8.1-5. Plot Plan of Particulate Control Equipment

8.1.4.3 Costs. Capital cost requirements for best particulate control are shown in Table 8.1-3. The major cost item is the particulate control equipment. Total capital requirement is $1,090,000. Annual costs are presented in Table 8.1-4, and are dominated by annualized capital recovery and downtime. Total annual costs are expected to be $235,000 per year.

8.1.5 Good Acid Gas Control

8.1.5.1 Description of Modifications. For good acid gas and CDD/CDF control, hydrated lime sorbent will be injected into the flue gas duct before the ESP. The lime sorbent will be fed at a molar ratio 2:1 (calcium to acid gas) for a rate of 227 lb/hr with both combustors operating. Additional equipment for sorbent injection will include a sorbent storage silo, a pneumatic sorbent transfer system, a sorbent feed bin, and pneumatic injection nozzles. To cool the flue gas from 450^0F to 350^0F, spray nozzles, also located in the duct before the ESP, will introduce 4 gpm of water. Fifty feet of new duct will be fabricated containing the water and sorbent nozzles.

A total of 19,000 square feet of ESP collection area will be required to collect the sorbent and fly ash to an emission level of 0.01 gr/dscf. Therefore, an additional 7,500 square feet of collection area will be added to the model plant ESP. The additional area will be installed as a separate single-field ESP in series with the existing ESP. Installation of the new ESP will also require 50 feet of new duct and a new ID fan. The proposed equipment arrangement is shown in Figure 8.1-6. New monitoring equipment for SO_2, HCl, O_2 and CO_2 is also included. Downtime is estimated at one month.

8.1.5.2 Environmental Performance. CDD/CDF emissions are expected to be reduced to 25 percent of inlet levels or to 50 ng/dscm, whichever is greater. Acid gas emission reductions are expected to be 80 percent for HCl and 40 percent for SO_2. Particulate matter emissions will be reduced to 0.01 gr/dscf. Additional collected fly ash and sorbent will add 1190 tons per year of solid waste to the baseline disposal requirements for the plant.

8.1.5.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 8.1-5. Total capital cost is $2,070,000. Most of the cost is associated with new equipment for particulate and temperature control. A moderate access and congestion level is assumed for all equipment except the duct containing the spray nozzles. Since this duct passes through

TABLE 8.1-3. PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
PM Control[a]	
Upgrade Costs	587
Access/Congestion Cost	147
New Flue Gas Ducting[a]	
Ducting Costs	15
Access/Congestion Cost	4
Other Equipment	
Fan	74
Stack	0
Demolition/Relocation	0
Total	827
Indirect Costs and Contingencies	267
Monitoring Equipment	0
TOTAL CAPITAL COST	1,090
DOWNTIME COST	205
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	171

[a] Based on moderate access/congestion.

TABLE 8.1-4. PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROLS (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	10
Electricity	3
Waste Disposal	1
Monitors	0
Total	14
INDIRECT COSTS:	
Overhead	6
Taxes, Insurance, and Administration	44
Capital Recovery and Downtime	171
Total	221
TOTAL ANNUALIZED COST	235

TABLE 8.1-3. PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
PM Control[a]	
Upgrade Costs	587
Access/Congestion Cost	147
New Flue Gas Ducting[a]	
Ducting Costs	15
Access/Congestion Cost	4
Other Equipment	
Fan	74
Stack	0
Demolition/Relocation	0
Total	827
Indirect Costs and Contingencies	267
Monitoring Equipment	0
TOTAL CAPITAL COST	1,090
DOWNTIME COST	205
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	171

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[a] Based on moderate access/congestion.

TABLE 8.1-4. PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROLS (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	10
Electricity	3
Waste Disposal	1
Monitors	0
Total	14
INDIRECT COSTS:	
Overhead	6
Taxes, Insurance, and Administration	44
Capital Recovery and Downtime	171
Total	221
TOTAL ANNUALIZED COST	235

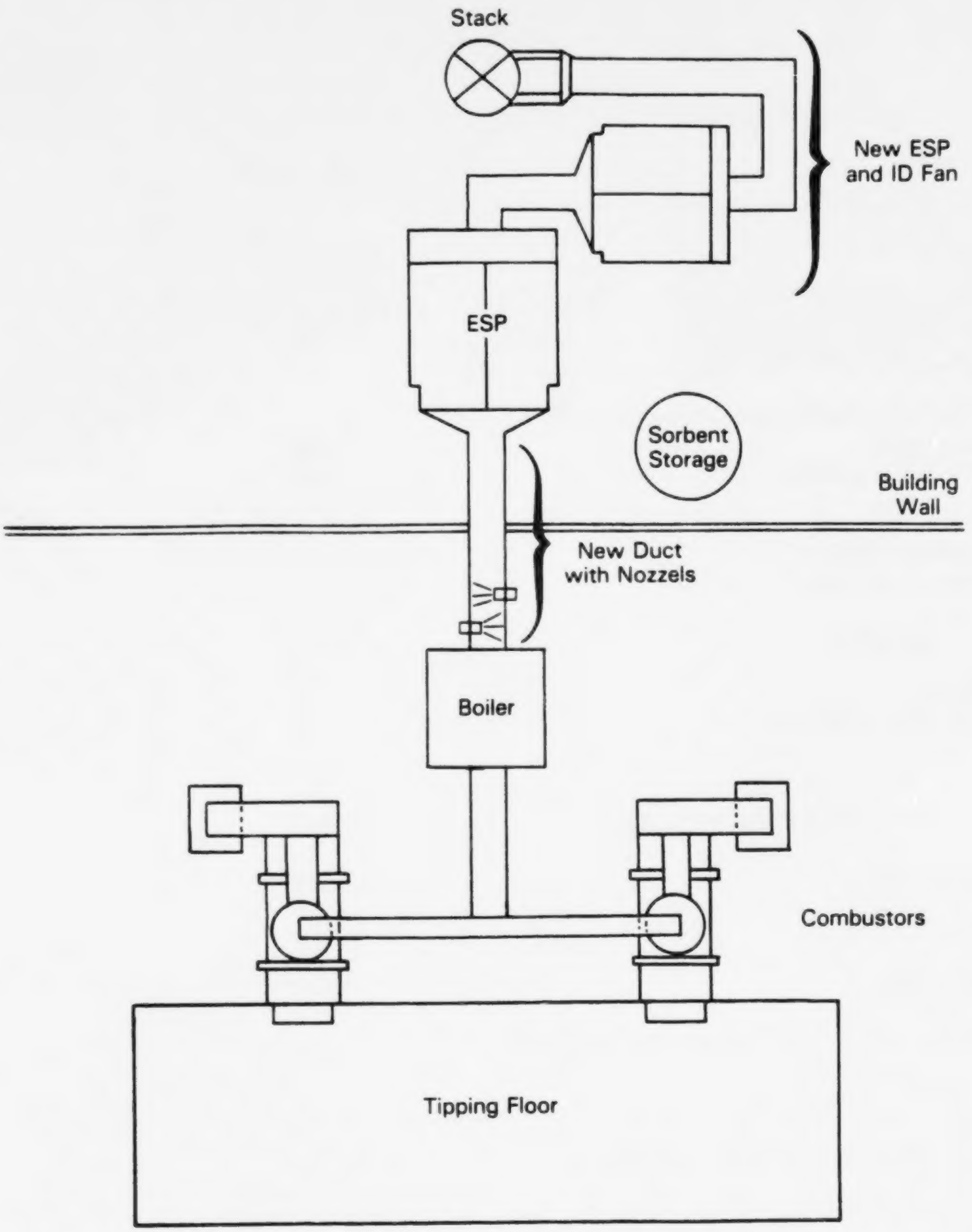

Figure 8.1-6. Plot Plan of Dry Sorbent Injection Equipment Arrangement

TABLE 8.1-5. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA
(Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas Control[a]	
Equipment	189
Access/Congestion Cost	19
Particulate and Temperature Control[b]	
Equipment	785
Access/Congestion Cost	160
New Flue Gas Ducting[a]	
Ducting Cost	31
Access/Congestion Costs	11
Other Equipment	
Fans	68
Stacks	0
Demolition/Relocation	0
Total	1,260
Indirect Costs and Contingencies	545
Monitoring Equipment[c]	257
TOTAL CAPITAL COST	2,070
DOWNTIME COST	205
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	299

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[a] Based on moderate access/congestion.

[b] Based on high access/congestion for temperature control ductwork.

[c] Turnkey.

the building wall, a high access/congestion factor was applied to the direct cost.

Annual costs are presented in Table 8.1-6. The major operating costs are for lime purchase and monitoring equipment maintenance. The largest annual cost is annualized capital recovery and downtime. Total annual cost is estimated to be $705,000.

8.1.6 Best Acid Gas Control

8.1.6.1 Description of Modifications. To achieve greater reductions in CDD/CDF, HCl, and SO_2, a spray dryer/fabric filter system will be installed. The existing ESP will not be demolished, but will be bypassed and left in place. A total of 100 feet of new duct will be used to connect the new equipment between the boiler outlet and the existing stack. The proposed equipment arrangement is shown in Figure 8.1-7.

Lime slurry will be introduced into the spray dryer at a calcium-to-acid gas molar ratio of 2.5:1. Water in the lime slurry equivalent to 6 gpm is needed to cool the gas stream from 450^0F to 300^0F.

The lime receiving, storage and slurry preparation area is also shown in Figure 8.1-7. The fabric filter will have 11,300 square feet of cloth area (net air-to-cloth ratio of 4:1). The increased pressure drop of the fabric filter relative to the existing ESP will require replacement of the ID fan. New monitoring equipment for HCl, SO_2, CO_2, O_2 and opacity will be installed. Downtime is expected to be one month for ductwork tie-ins.

8.1.6.2 Environmental Performance. CDD/CDF emission reduction of 99 percent or to 5 ng/dscm (whichever gives higher emissions) is expected. Emissions of particulate matter will be reduced to 0.01 gr/dscf. Acid gas emissions will be reduced 90 percent for SO_2 and 97 percent for HCl.

8.1.6.3 Costs. Capital costs for installing a spray dryer/fabric filter system are shown in Table 8.1-7. Total capital cost is $4,720,000. The major capital cost is for the purchased equipment. A moderate access/congestion factor was applied to all direct equipment costs. Annual costs are shown in Table 8.1-8. The largest annual costs are for maintenance materials, including bag replacement, and annualized capital recovery and downtime. Maintenance cost for process monitors is also significant. Total annual cost is estimated at $1,320,000 per year.

TABLE 8.1-6. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA
(Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	30
Supervision	5
Maintenance Labor	20
Maintenance Materials	14
Electricity	15
Water	1
Lime	72
Waste Disposal	30
Monitors	103
Total	290
INDIRECT COSTS:	
Overhead	44
Taxes, Insurance, and Administration	72
Capital Recovery and Downtime	299
Total	415
TOTAL ANNUALIZED COST	705

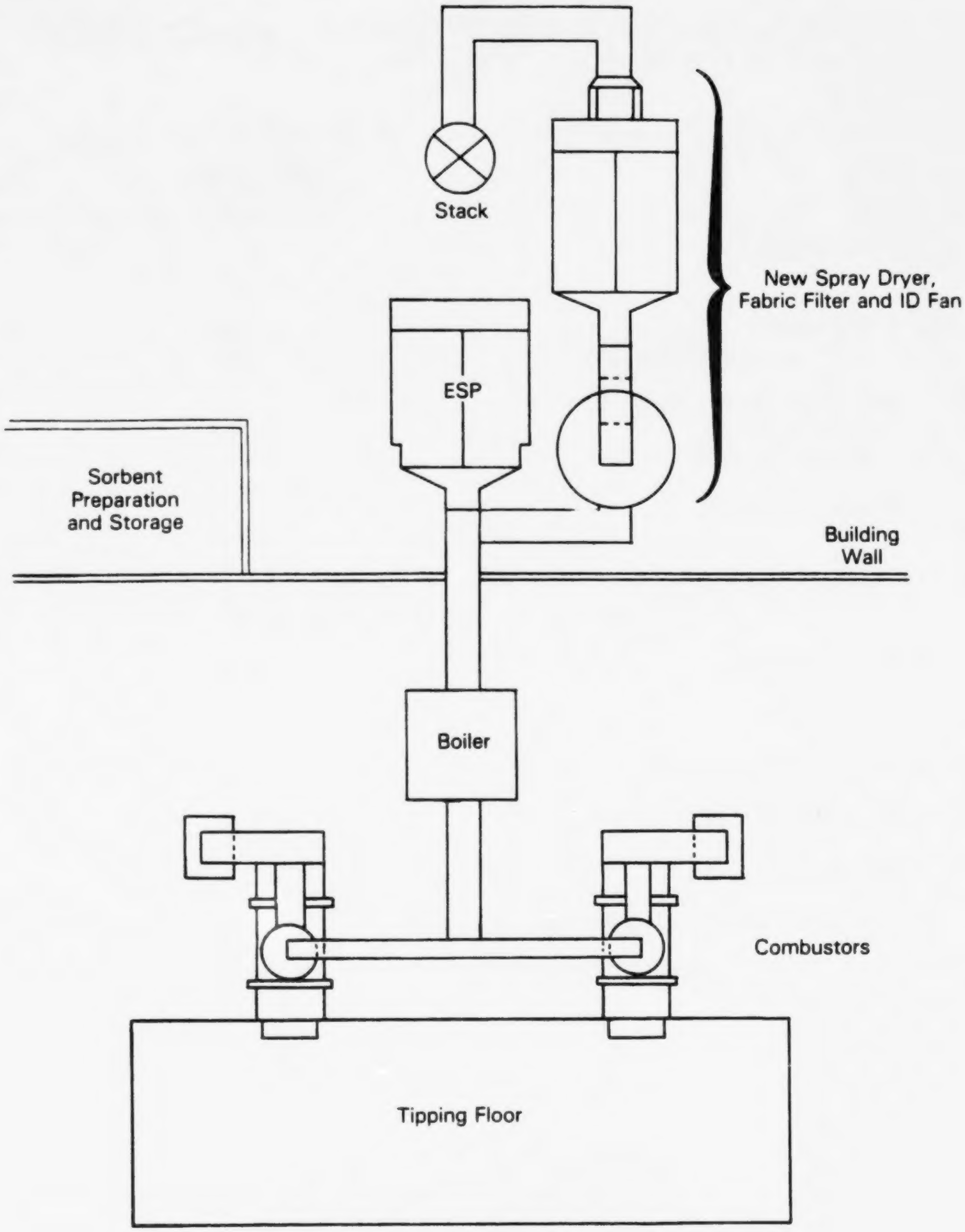

Figure 8.1-7. Plot Plan of Spray Dryer/Fabric Filter Retrofit Equipment Arrangement

TABLE 8.1-7. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas Control	
Equipment	2,130
Access/Congestion Cost	533
New Flue Gas Ducting	
Ducting Cost	30
Access/Congestion Cost	8
Other Equipment	
Fans	74
Stacks	0
Demolition/Relocation	0
Total	2,780
Indirect Costs	917
Contingency	739
Monitoring Equipment[a]	286
TOTAL CAPITAL COST	4,720
DOWNTIME COST	205
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	648

[a] Turnkey.

TABLE 8.1-8. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 100 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	48
Supervision	7
Maintenance Labor	26
Maintenance Materials	67[a]
Electricity	48
Compressed Air	6
Water	1
Lime	60
Waste Disposal	39
Monitors	107
Total	410
INDIRECT COSTS:	
Overhead	82
Taxes, Insurance, and Administration	177
Capital Recovery and Downtime	648
Total	907
TOTAL ANNUALIZED COST	1,320

[a] Includes bag replacement costs of $11,000.

8.1.7 Summary of Control Options

8.1.7.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 8.1-9 summarizes the combustion, particulate, temperature, and acid gas control technologies described in Sections 8.1.3 through 8.1.6 that were combined for each of the control options described in Section 3.0.

It should be noted that since the model plant already achieves moderate PM control at baseline, Options 1 and 2 are identical. Also, since the model plant achieves good combustion at baseline, Options 1 and 2 are equivalent to baseline, Options 4 and 5 are identical, and Options 6 and 7 are identical.

8.1.7.2 Environmental Performance. The performance of each control option is summarized in Table 8.1-10. For each pollutant, the table presents both the pollutant concentrations and emissions. The greatest emission reductions of acid gases, particulate matter, and CDD/CDF all are achieved with the spray dryer/fabric filter system. The next most effective control for all these pollutants is dry sorbent injection. Both sorbent addition technologies increase solid waste slightly (less than 10 percent over baseline). No combustion modifications were made, so CO emissions remain unchanged at 50 ppm for all options.

8.1.7.3 Costs. The total annualized cost of each option is presented in Table 8.1-11. The most costly control option is the spray dryer/fabric filter installation, at a capital cost of $4,720,000. Overall, costs are higher for higher levels of control, and are roughly double the cost of the previous control option.

8.1.7.4 Energy Impacts. Table 8.1-12 presents a summary of the energy impacts associated with the control options. The energy use figures are incremental use; savings realized by not operating the existing ESP are taken into account. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and are used under baseline operation.

TABLE 8.1-9. SUMMARY OF CONTROL OPTIONS FOR MODULAR EXCESS-AIR COMBUSTOR

Control Option Description	Combustion Modifications	Temperature Control	Particulate Control		Acid Gas Control		
			Existing ESP Rebuilt	Additional Plant Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion Control							
3. Best PM Control and Combustion and Temperature Control				X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/Temperature Control		X			X		X

TABLE 8.1-10. ENVIRONMENTAL PERFORMANCE SUMMARY FOR MODULAR EXCESS-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 100 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	200	200	200	200	50	50	5	5
Mg/yr	5.2E-5	5.2E-5	5.2E-5	5.2E-5	1.3E-5	1.3E-5	1.3E-6	1.3E-6
% Reduction vs. Baseline	--	0	0	0	75	75	98	98
CO Emissions								
(ppmv)	50	50	50	50	50	50	50	50
Mg/yr	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	29.8	29.8	29.8	6.0	6.0	6.0	6.0	6.0
% Reduction vs. Baseline	--	0	0	80	80	80	80	80
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	148	148	148	148	89	89	14	14
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	212	212	212	212	42	42	6	6
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	60	60	60	60	64	64	65	65
Mg/yr	18,200	18,200	18,200	18,200	19,300	19,300	19,600	19,600
% Increase vs. Baseline	--	0	0	0	6	6	8	8

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Standard and normal conditions are both 1 atmosphere and 70°F.

TABLE 8.1-11. COST SUMMARY FOR MODULAR EXCESS-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units of 100 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	1,090	2,070	2,070	4,720	4,720
Downtime Cost	0	0	205	205	205	205	205
Annualized Capital and Downtime Cost	0	0	171	299	299	648	648
Direct O&M Cost	0	0	14	290	290	410	410
Total Annual Cost	0	0	235	705	705	1,320	1,320
Cost Effectiveness ($/ton MSW)	0	0	3.52	10.60	10.60	19.80	19.80
Facility Downtime (Months)	0	0	1	1	1	1	1
Total Compliance Time (Months)	1	1	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

TABLE 8.1-12. ENERGY IMPACTS FOR MODULAR EXCESS-AIR COMBUSTOR MODEL PLANT CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	60	0
4	334	0
5	334	0
6	1,030[b]	0
7	1,030[b]	0

[a] Increase from baseline consumption.

[b] Excludes the electrical credit of not operating the ESP's.

8.2 REFERENCES

1. Epner, E., Radian Corporation, and Schindler, P., Energy and Environmental Research Corporation. Trip report - Retrofit Control Site Evaluation at the Pittsfield Waste to Energy Facility. March 31, 1988.

9.0 ROTARY WATERWALL COMBUSTORS

The O'Connor rotary waterwall combustion system is one of the more unique designs in the existing population of MWC's. There are currently three operating plants using the O'Connor design. Table 9.0-1 lists these plants along with number of combustors, unit size, start-up date, and air pollution control device. Individual plants are comprised of two combustors ranging in unit capacity from 100 to 255 tpd. Additional O'Connor-design plants are in planning, permitting, or construction stages in York County, PA; Delaware County, PA; Lubbock, TX; and Mercer County, NJ.

9.1 INTRODUCTION

This section presents the retrofit case study results for a mass burn rotary waterwall municipal waste combustor (MWC). Table 9.0-1 lists the three existing plants in this subcategory. Section 9.1.1 presents a description of the Bay County MWC plant, which was visited in order to gather information for model development. Section 9.1.2 presents a description of the model plant. Sections 9.1.3 through 9.1.7 detail the retrofit modifications, estimated performance, and costs associated with various control options, which are discussed in more detail in Section 3.0 of this report.

9.1.1 Description of the Bay County, FL Plant[1]

The Bay County Resource Management Facility consists of two Westinghouse - O'Connor rotary waterwall combustors designed to mass burn up to 255 tpd of MSW (total plant capacity 510 tpd). The combustors can also burn wood waste or a mixture of MSW and wood waste. Heat generated by combustion produces steam to drive a turbine generator. Design data are presented in Table 9.1-1, and a process flow diagram of the Bay County facility is shown in Figure 9.1-1. The facility is owned by New England Trust Company, leased by Bay County and operated (under a 25-year contract) by Westinghouse. Generated electricity is sold to Gulf Power at an average of 2.074 cents per kwh. The facility charges a tipping fee of $22 per ton and disposes of ash at the county-owned landfill at no direct charge. Waste disposal costs $3.72 per ton for contract hauling by truck to the landfill.

TABLE 9.0-1. EXISTING ROTARY WATERWALL COMBUSTORS

Plant/Location	No. of Units	Unit Size (tpd)	Year of Start-up	Air Pollution Control Device
Bay County, FL	2	255	1987	ESP
Poughkeepsie, NY	2	253	1987	Fabric Filter
Gallatin, TN	2	100	1981	ESP

TABLE 9.1-1. BAY COUNTY, FLORIDA DESIGN DATA

Furnaces:	
Number	2
Capacity	255 tpd
Furnace Dimensions	Each combustor consists of a tapered barrel 10 feet in diameter and 40 feet long.
Emission Controls:	
Numbers	2 (one for each furnace)
Type	3-field ESP
Gas Flow	56,000 acfm at 400°F each
Collection Area	19,710 ft^2 each
SCA	350 ft^2/1000 acfm
Dimensions	
Length	30 ft
Width	18 ft
Height	24 ft
Gas Velocity	4 ft/sec
Inlet Concentration	2.0 gr/dscf at 12% CO_2
Exit Concentration	0.02 gr/dscf at 12% CO_2
Generating Capacity:	
Steam (each boiler)	68,800 lb/hr at 600 psi, 750°F
Electricity (site total)	11.5 MW

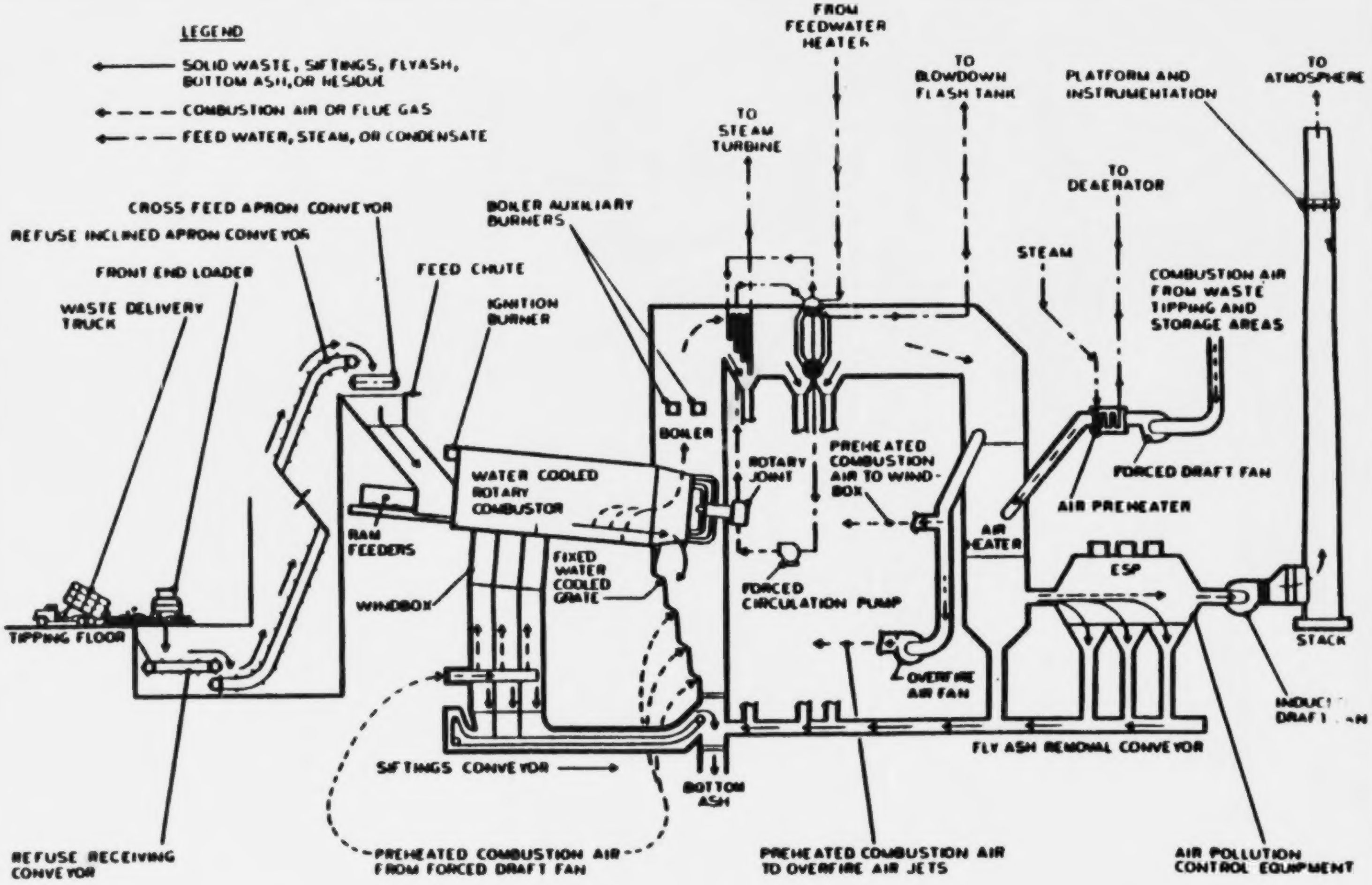
LEGEND
SOLID WASTE, SIFTINGS, FLYASH, BOTTOM ASH, OR RESIDUE
COMBUSTION AIR OR FLUE GAS
FEED WATER, STEAM, OR CONDENSATE
CROSS FEED APRON CONVEYOR
REFUSE INCLINED APRON CONVEYOR
FRONT END LOADER
WASTE DELIVERY TRUCK
TIPPING FLOOR
REFUSE RECEIVING CONVEYOR
FEED CHUTE
IGNITION BURNER
RAM FEEDERS
WINDBOX
WATER COOLED ROTARY COMBUSTOR
FIXED WATER COOLED GRATE
SIFTINGS CONVEYOR
PREHEATED COMBUSTION AIR FROM FORCED DRAFT FAN
BOTTOM ASH
BOILER AUXILIARY BURNERS
BOILER
TO STEAM TURBINE
FROM FEEDWATER HEATER
TO BLOWDOWN FLASH TANK
ROTARY JOINT
FORCED CIRCULATION PUMP
PREHEATED COMBUSTION AIR TO WIND-BOX
OVERFIRE AIR FAN
PREHEATED COMBUSTION AIR TO OVERFIRE AIR JETS
AIR HEATER
STEAM
TO DEAERATOR
AIR PREHEATER
FORCED DRAFT FAN
COMBUSTION AIR FROM WASTE TIPPING AND STORAGE AREAS
ESP
FLY ASH REMOVAL CONVEYOR
AIR POLLUTION CONTROL EQUIPMENT
INDUCED DRAFT FAN
STACK
PLATFORM AND INSTRUMENTATION
TO ATMOSPHERE

Figure 9-1.1. **Simplified Process Flow Diagram, Gas Cycle for the Westinghouse-Bay Resource Management Center**

Construction of the facility began in November 1985, and waste was first burned in February 1987. Start-up testing in May 1987, demonstrated contractual commitments of burning 510 tpd, generating 11.5 MW gross electric power output, and leaving less than 11 percent combustibles in the ash. The facility employs 35 people and has operated on a 24-hour/day, 7-day/week schedule since commercial start-up in May 1987. To maintain this schedule, the facility frequently burns wood waste (bark or sawdust) in one combustor, and MSW or a mixture of MSW and wood in the other combustor. The average heating value of MSW is 4,500 to 5,000 Btu/lb. However, the estimated heating value of the mixed fuel is 3,800 to 4,000 Btu/lb due to the high moisture content of the wood, which has an average heating value of 3,000 to 3,500 Btu/lb. Wood is purchased for an average of $10 per ton. The MSW supply is seasonal in Bay County, which is a resort area, but even in the peak summer season the MSW supply has not yet met plant capacity. In the winter, the plant typically burns 250 tpd MSW, 50 tpd commercial waste and trash, and 210 tpd wood waste. In the summer, the feed is 380 tpd MSW, 50 tpd commercial waste and trash, and 80 tpd wood waste. Westinghouse is currently seeking out-of-county waste to replace some of the wood fuel.

9.1.1.1 Combustor Design and Operation. Waste is delivered to the plant and dumped on the tipping floor, which accommodates about 1,500 tons of waste. The waste is then sorted to remove large objects, mixed thoroughly, and pushed onto one of two horizontal apron conveyors by a front-end loader. A shear shredder is available for shredding large combustible items, but is not often used. About 3 percent of the waste is rejected as non-combustible and delivered intact to the landfill.

Each horizontal apron conveyor transfers waste feed onto separate parallel inclined conveyors which contain weigh scales to continuously measure the weight of waste being delivered to the charging hopper. One additional horizontal conveyor is located at the charging hopper level to allow waste from one conveyor line to be sent to an adjacent combustor. Therefore, both combustors can be supplied from one conveyor line in the event that the parallel line is down for maintenance. From the charge chute, MSW is pushed into the combustor by dual hydraulic ram feeders. The ram speed is adjusted by the computerized combustion control system, but the time to complete a stroke is usually 3.5 minutes. The Bay County rotary drum (barrel) sits at a 6° angle from the horizontal and is tapered over the final 4 feet. The Bay County units are the only O'Connor facilities that use a tapered barrel. The combustor barrel rotates slowly (3 to 7 rph) causing the waste to tumble and advance as it burns. At the typical rotation speed of 5 rph, the waste remains in the combustor for approximately 30 minutes. The ram speed and the rotation speed are automatically adjusted to maintain constant bed profile. This practice is designed to maximize waste burnout at the barrel exit. The combustor barrel is 10 feet in diameter, 40 feet long, and is constructed of steel tubes and perforated webs (see Figure 9.1-2). The tubes direct cooling water through the outside wall of the combustor barrel and to the boiler, and thus, the rotary portion is considered an integral part of the boiler radiant section. The combustor barrel protrudes approximately 5 feet into the boiler. Bottom ash is discharged from the rotary combustor onto a stationary after-burning grate and then into the wet quench pit.

A forced-draft fan draws combustion air from the tipping area. This air is preheated to $450^{\circ}F$ and then enters a multiple-zone windbox beneath the combustor barrel. Westinghouse defines underfire air and overfire air differently from the classic mass-fired system. The three plenums are separated laterally into two sections each (3x2 arrangement). The rotation of the drum dictates the location of the fuel bed. Air supplied through the three windboxes beneath the fuel bed is designated underfire air, and the air directed through the adjacent three windboxes is overfire air. Figure 9.1-2 shows the cross-section of the rotary combustor and the flow of overfire and underfire air. The air supplied to the rotary combustor is distributed to the three windboxes as 40, 40 and 20 percent, front to rear. In the first and second windbox section the overfire/underfire air ratio is 40/60. In the third section the ratio is 50/50. These splits are reported as estimated normal operating conditions, and they are adjustable. Under normal operating conditions, 80 percent of the total air is delivered to the rotary combustor. Five percent of the total air is supplied below the afterburning grate. The remaining 15 percent of the total air is drawn from

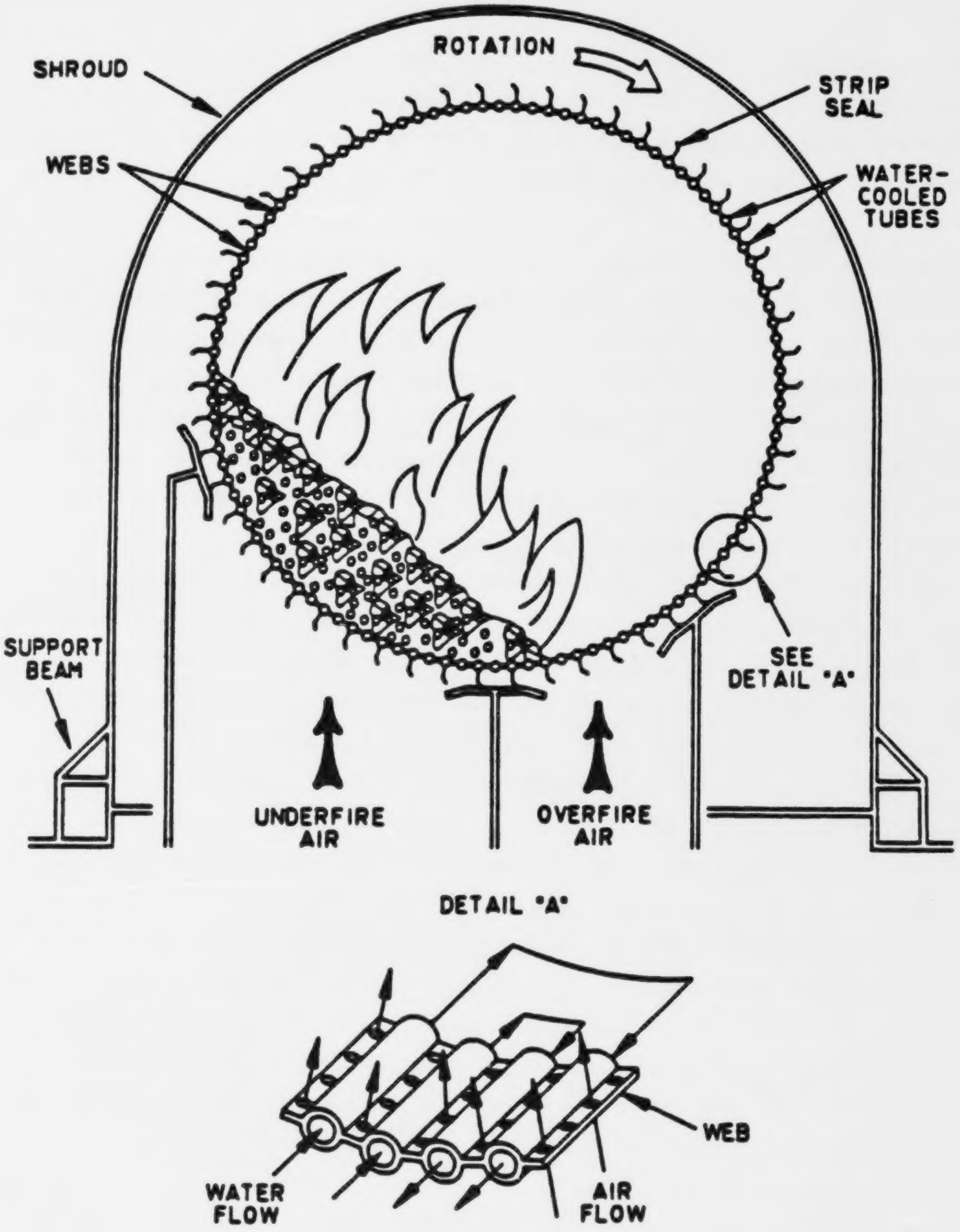

Figure 9.1-2. Cross-Section of the Westinghouse O'Connor Water-Cooled Rotary Combustor

the duct supplying the rotary combustor and delivered as tertiary air through overfire air nozzles. Two rows of opposed 2-1/2 inch diameter overfire air nozzles are located on the front and rear walls of the boiler approximately 10 feet above the rotary combustor. There are 34 nozzles on each wall.

The waste feed rate is maintained by the Westinghouse computer controller, but the setpoint can be adjusted by the operator based on fuel characteristics. The combustion air flow is also controlled automatically to maintain desired steam flows. The air flow rate to the drying zone is based on the combustor inlet temperatures. Air flows to the combustion and burnout zones control firing rates and are based on the exit gas oxygen content. Ram speed and combustor rotation are adjusted to maintain the exit gas conditions at 1400°F and 5.0 to 5.7 percent O_2 (wet).

The Bay County facility is equipped with a recuperative tubular air heater. To protect against corrosion in the air heater, a steam preheater is located at the air inlet to increase the temperature from ambient to 150°F. The steam drums of each boiler are connected by piping so that steam generated in one unit can be distributed to the adjacent boiler to aid in preheating the heat recovery equipment during process start up. Therefore, if outages are scheduled independently, the boiler that is down can be preheated to 300°F by steam from the operating unit, shortening the time required to come up to full operating load.

The flue gases exit the air heater and are pulled through the electrostatic precipitator (ESP) by an induced-draft fan before exiting the stack. The stack is precast concrete with two 4-ft, 6-in. diameter flues constructed of 4-inch acid brick. The stack is 125 feet tall and has monitoring ports 60 feet above the base. In addition to continuous oxygen monitors located at the boiler exits, the plant also operates opacity and CO monitors downstream of the ESP's.

Each boiler is designed to produce 68,800 lb/hr of 600 psi, 750°F super-heated steam. The steam flows to a multiple extraction condensing turbine generator which produces about 11.5 MW of 3-phase, Hz electrical power for distribution to the utility grid. Transformers provide power at reduced voltage for plant use. Turbine exhaust steam is condensed in a shell and tube heat exchanger that is cooled by an external cooling tower using 200,000 gpd well water. Steam condensate is pumped back to the boiler through feedwater heaters and a deaerator.

As stated previously, bottom ash leaves the combustor barrel via a steeply inclined burnout grate, and drops into a wet quench pit. The bottom ash is removed from the quench pit by dual drag chain conveyors which dump the wet ash into waiting trucks for transportation to the landfill. Discharge chutes are adjustable to allow all the ash from both combustors to be delivered to one of the removal systems. Fly ash collected in the boiler and ESP is pneumatically conveyed to the quench pit for disposal. Siftings collected on a conveyor beneath the combustor are also added to the quench pit. Total ash combustibles are normally 11 percent by weight. An average of 150 tpd wet ash (11 truckloads) is hauled to the county landfill. The county-owned landfill is a lined mono-cell facility with leachate collection located on a 155-acre site approximately 39 miles from the incinerator site.

Auxiliary fuel oil burners are available to preheat the combustor to 400^{0}F, but are only used if both combustors have been down. Normally, steam from an operating boiler is used to preheat the adjacent cold boiler. One fuel oil burner is located in the combustor and used to ignite the waste. Two others are located in the walls of the boiler radiant section.

During the visit it was noted that boiler operating temperatures were higher than design, and particulate carryover from the discharge of the rotary combustor seemed relatively high. The units were operating on wood waste during the visit.

Bay County is the second facility in the U.S. to burn MSW in the O'Connor combustor, and the first to be constructed by Westinghouse. The first plant to use the O'Connor technology is located in Gallatin, TN. Performance tests executed at Gallatin have provided information leading to some design changes in subsequent O'Connor systems. As an example, CO profiling tests performed at Gallatin demonstrated the need for overfire air above the rotary combustor exit, as well as the need for some air to be supplied to the burnout grate below the barrel. These air sources, which were once eliminated at Gallatin, were shown to be necessary and were reinstituted in the design. However, the design configuration at Bay County was established prior to completion of all the performance evaluations at Gallatin. For example, the Gallatin tests were instrumental in changing the design of the barrel such that the rotary section will not protrude as far into the radiant section of the boiler in the future designs, thus eliminating the increased potential for unmixed pockets of combustion gases below the extended rotary sections.

9.1.1.2 Emission Control System Design and Operation. Flue gases from each combustor exit the gas heater and enter a 3-field ESP. Each field has an electrical set and ash hopper. The ESP's are the rigid frame type with plate dimensions of 24 feet high by 9 feet long, with 1/2 inch diameter pipe electrodes. Total collection area for each ESP is 19,710 ft^2 and the design gas flow rate for each is 56,000 acfm at 400^0F (SCA = 350 ft^2/1000 acfm). Actual ESP inlet temperature is approximately 450^0F at full rate.

The ESP's were designed to meet the Florida Department of Environmental Regulation emission limit of 0.03 gr/dscf at 12 percent CO_2. Compliance tests for the facility have shown actual emissions of 0.02 gr/dscf and inlet loadings of approximately 2.0 gr/dscf. Opacity is in compliance as well, at less than 10 percent. Table 9.1-2 summarizes recent compliance test results and gaseous emission tests used to support the plant's PSD permit application.

9.1.2 Description of Model Plant

9.1.2.1 Combustor Design and Operation. There are three existing MWC's which use the O'Connor rotary waterwall technology (Gallatin, Bay County, and Dutchess County, NY). Gallatin began operating in 1981, using two 100-tpd combustors. Bay County began operating in 1987, using two 255-tpd units. Dutchess County started operating in 1988, using two 253-tpd combustion units. In an attempt to configure the model plant to represent the existing population, two 250-tpd units were selected for the model. (Model plant design data are summarized in Table 9.1-3.) with the exception of Gallatin, the facilities have state-of-the-art automatic combustion control systems and auxiliary fuel firing capacity. In addition, the newer facilities use rows of high pressure tertiary air nozzles to complete the mixing process in the radiation section of the boiler. As described in the preceding section, the Gallatin plant has added a similar set of nozzles

TABLE 9.1-2. BAY COUNTY, FLORIDA EMISSIONS SUMMARY[a]

	Permitted Values	Unit 1	Unit 2
Particulate Matter (gr/dscf)	0.03 (10% opacity)	0.019	0.024
SO_2 (dry ppmv)	NA	133	84
NO_x (dry ppmv)	NA	NA	169
HCl (dry ppmv)	NA	428	508
CO (dry ppmv)	NA	NA	68
CDD/CDF	NA	NA	NA

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[a] All values corrected to 12% CO_2 basis except CO, which is on 7% O_2 basis. CDD/CDF data were measured, but have not yet been reported.

TABLE 9.1-3. MODEL PLANT BASELINE DATA FOR ROTARY WATERWALL COMBUSTOR

Combustors:	
Type	- Rotary Waterwall
Manufacturer	- Westinghouse/O'Connor
Number of Combustors	- 2
Combustor Unit Capacity	- 250 tpd each
Plant Capacity	- 500 tpd
Emission Controls:	
Type	- Electrostatic Precipitator
Number	- 2 (one per combustor)
Number of Fields	- 3 each
Inlet Temperature	- 450^{0}F
Collection Efficiency	- 98.5 percent
Gas Flow	- 49,000 acfm each
Total Plate Area	- 16,300 ft^{2} each
SCA at 47,000 acfm and 450^{0}F	- 335
Emissions:[a]	
CDD/CDF (tetra-octa)	- 2000 ng/dscm
PM (stack)	- 0.03 gr/dscf[b]
CO	- 100 ppmv
HCl	- 500 ppmv
SO_2	- 200 ppmv
Stack Parameters:	
Height	- 125 feet
Diameter	- 4 feet (per flue)
Operating Data:	
Remaining Plant Life	- ≥ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $5,720,000/year

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[a] All emissions are dry, corrected to 7 percent O_2. Standard and normal conditions are both 70^{0}F and 1 atmosphere.

[b] Inlet PM emissions to the ESP are 2.0 gr/dscf at 7 percent O_2.

which are an essential component of good combustion practice. Because the majority of existing plants have these design features, is is appropriate to include them in the model. It is assumed that the distribution of combustion air in the model plant is the same as that reported for the Bay County facility, with 80 percent of the total air delivered to the rotary combustor, 15 percent injected through the tertiary nozzles, and 5 percent supplied to the burnout grate.

The model plant is assumed to operate on a 24-hr/day, 7-day/week schedule, burning 100 percent MSW. The basic plant configuration is assumed to be similar to Bay County, including ram feeders, three underfire air plenum sections along the length of the rotary combustor, and one row of tertiary air nozzles on each of the front and rear walls in the radiation section of the boiler above the discharge of the rotary combustor. A burnout grate is located at the exit of the rotary combustor, and the bottom ash is discharged into a water quench pit.

The O'Connor combustion system typically operates in the range of 25 to 75 percent excess air. An average value of 50 percent excess air is assumed for the model plant. At 50 percent excess air, total flue gas flow rate exiting the heat recovery equipment is approximately 23,900 dscfm per unit. Based on the available information for Gallatin and Bay County, the flue gas temperatures at the economizer outlet typically range from 350 to 450°F. A value of 450°F is selected for the model plant.

Continuous monitors are in place to verify combustor flue gas oxygen levels and temperatures. It is assumed that CO monitors are in place at the model plant.

As discussed in Section 9.1.1.1, the Bay County facility is the only operating plant that uses a tapered barrel. In addition, at Bay County the rotary combustor protrudes into the radiation section of the boiler. This has been shown to result in dead zones where mixing is prevented and higher CO measurements are observed. Bay County is also the only existing facility to use an extended barrel. Therefore, the assumed configuration of the model plant does not include the tapered, extended barrel.

9.1.2.2 Emission Control System Design and Operation. The Bay County plant has 3-field ESP's that reduce PM emissions to 0.02 gr/dscf from 2.0 gr/dscf, but measured emissions at Gallatin and expected emissions from plants currently under construction are higher. Therefore, the model plant is assumed to have two 3-field ESP's that reduce PM emission to 0.03 gr/dscf (corrected to 7 percent O_2.) The Bay County single stack with two flues will be retained for the model plant. Stack parameters are presented in Table 9.1-3, and a plot plan of the model plant is shown in Figure 9.1-3.

9.1.2.3 Environmental Baseline. Table 9.1-3 also presents baseline emissions data for the plant. All baseline emissions are presented corrected to 7 percent O_2. Bay County and Gallatin both have reported data for all the pollutants of concern, with the exception of CDD/CDF. Baseline particulate emissions are estimated to be 2 gr/dscf) at the inlet to the ESP. This is typical of a conventional mass burn waterwall facility. The measured CO values at Bay County are reported to vary from 50 to 100 ppmv. A baseline value of 100 ppmv is assumed for the model plant. Based on calculations of jet penetration, it is determined that the existing tertiary air system is not adequate to provide the required coverage and penetration of the furnace cross section. As a result, relatively large quantities of fuel-rich gases escape the combustor without being mixed. When combined with an uncontrolled particulate emission rate of 2 gr/dscf, there is potential for extensive catalytic reaction of the organics to form CDD/CDF. As such, baseline uncontrolled tetra through octa CDD/CDF emissions are established at 2,000 ng/dscm. As with the other mass burn models, uncontrolled HCl and SO_2 emissions are assumed to be 500 ppmv and 200 ppmv respectively. The combustors are assumed to achieve 90 percent waste volume reduction and 70 percent weight reduction.

9.1.3 Good Combustion

9.1.3.1 Description of Modifications. Modification to the existing overfire (tertiary) air nozzles is required in order to achieve the proper mixing through penetration and coverage of the furnace cross section. A properly designed and operated tertiary air supply will ensure that the combustion gases are thoroughly mixed and that CDD/CDF emissions are minimized. In order to establish an effective design, flow modeling studies are required to determine the proper nozzle size, number, velocity, and

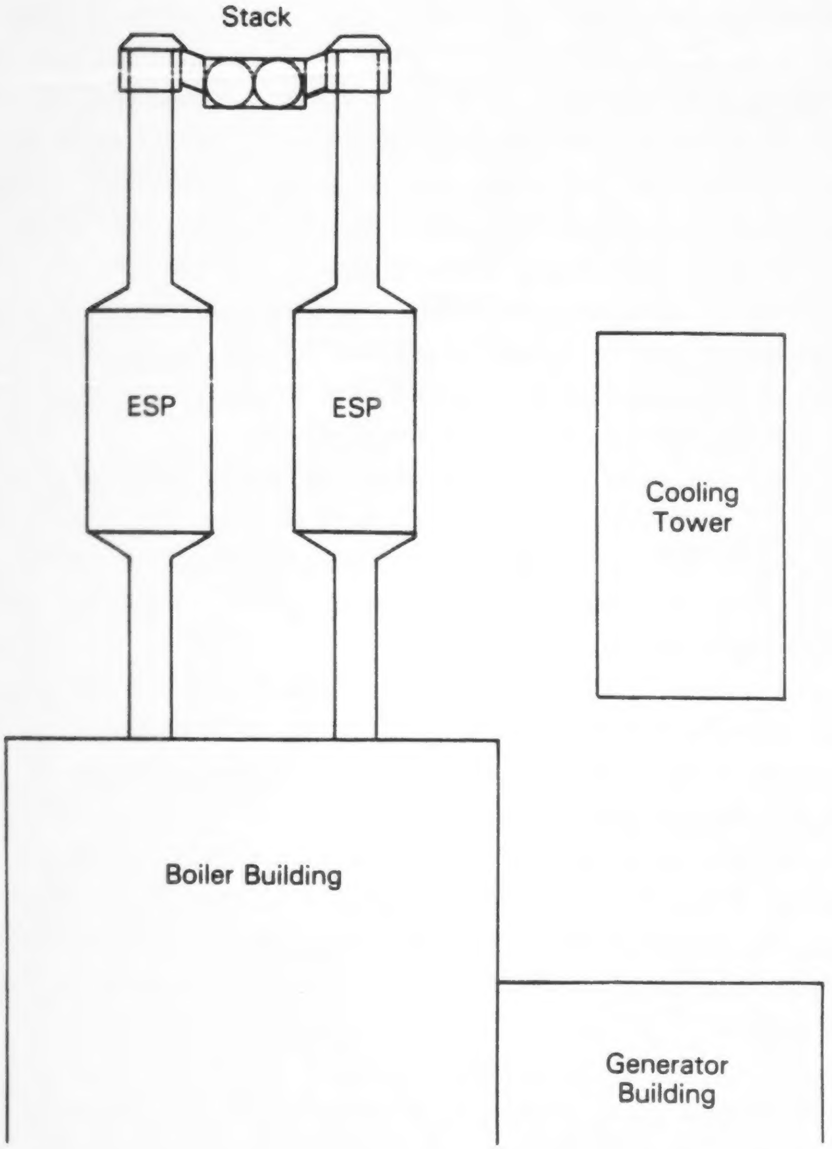

Figure 9.1-3. Model Plant Plot Plan

and spacing. In addition, the nozzles should be designed with the ability to supply at least 40 percent of the total combustion air to the system. Because the waterwalls in this section of the boiler are a welded wall construction, it is assumed that new waterwall panels will be required with tube bends around the overfire air nozzles.

Following a successful redesign of the tertiary air nozzles, the model plant will have the design, operation/control, and verification measures in place which constitute good combustion practices. The 1800°F temperature is attained and auxiliary fuel is in place to use during start up and low temperature/high CO conditions. The necessary flue gas monitors are in place to briefly operation conditions. The flue gas temperatures at the economizer outlet are low enough to prevent CDD/CDF formation from occurring. The new nozzles will ensure that mixing of the exhaust gases is achieved and CDD/CDF concentrations are minimized.

9.1.3.2 Environmental Performance. Following redesign of the overfire air nozzles the effect on pollutant emission levels will be a reduction in CDD/CDF emissions from the baseline values to 400 ng/dscm. No additional pollutant reductions can be anticipated. Downtime is estimated to be three weeks for each combustor.

9.1.3.3 Costs. Capital costs for combustion modifications are presented in Table 9.1-4. Total capital costs are $295,000. Annual costs are presented in Table 9.1-5. Annual cost is $109,000 per year.

9.1.4 Best Particulate Control

The ESP's in place on the model plant reduce PM emissions by 98.5 percent from 2.0 gr/dscf to 0.03 gr/dscf (corrected to 7 percent O_2). Therefore, the baseline PM emission rate is lower than the rate identified with good control (0.05 gr/dscf), and no plant modifications will be required for good control.

9.1.4.1 Description of Modifications. To achieve best particulate control (0.01 gr/dscf) will require an ESP with 20,600 square feet of collection area for each combustor. To obtain this performance, each existing ESP will be upgraded with 4300 square feet of additional plate area. Fifty feet of ductwork will be replaced between each ESP and the

TABLE 9.1-4. PLANT CAPITAL COST FOR COMBUSTION MODIFICATIONS[a]
(Two units of 250 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Flow Modeling		75
Overfire Air Nozzles		122
	Total	197
INDIRECT COSTS AND CONTINGENCIES:		98
TOTAL CAPITAL COSTS		295
DOWNTIME COST		441
ANNUALIZED CAPITAL AND DOWNTIME		97

[a] All costs are in December 1987 dollars.

TABLE 9.1-5 PLANT ANNUAL COST FOR COMBUSTION MODIFICATIONS
(Two units of 250 tpd each)

Item		Cost ($1,000)
DIRECT COSTS:		
Operating Labor		0
Maintenance Labor		0
Maintenance Materials		0
	Total	0
INDIRECT COSTS:		
Overhead		0
Taxes, Insurance, and Administration		12
Capital Recovery and Downtime		97
	Total	109
TOTAL ANNUALIZED COST		109

stack. A a plot plan of the equipment arrangement is shown in Figure 9.1-4. The existing ID fans will be retained. No new monitoring equipment will be installed. Downtime is estimated to be one month for each combustor.

9.1.4.2 Environmental Performance. Particulate matter emissions will be reduced from 0.03 gr/dscf to 0.01 gr/dscf. No other pollutant of interest will be affected. The increased fly ash recovery will add 33 tons per year to the baseline solid waste disposal requirements for the plant.

9.1.4.3 Costs. Capital costs for particulate control upgrade are presented in Table 9.1-6. The major capital cost is purchased particulate control equipment. A moderate access and congestion factor was used to estimate the total capital cost. Total capital required is $1,990,000. Downtime costs are $588,000 and are primarily lost revenues from electrical generation. Annual costs are shown in Table 9.1-7. The largest annual cost is annualized capital recovery and downtime. Total annual cost is $456,000 per year.

9.1.5 Good Acid Gas Control

9.1.5.1 Description of Modifications. For good CDD/CDF and acid gas control, hydrated lime will be injected into the flue gas duct before the ESP. The lime sorbent will be fed at a molar ratio of 2:1 (calcium-to-total acid gas) for a rate of 283 lb/hr per combustor. Site equipment for sorbent injection will include a sorbent storage silo, a pneumatic sorbent transfer system, pneumatic nozzles, and a sorbent feed bin for each combustor. To cool the flue gas from 450^{0}F to 350^{0}F, water spray nozzles, also located in the duct before the ESP inlet, will introduce 5 gpm of water. Fifty feet of new duct for each combustor will be fabricated containing the water and sorbent nozzles.

A total of 23,750 square feet of ESP collection area will be required to collect the sorbent and fly ash from each combustor at an emission rate of 0.01 gr/dscf. The additional 7,450 square feet of required collection area will be added as a new single-field ESP in series behind the existing ESP. Installation of the two new ESP's will also require 100 total feet of new ductwork and two new ID fans. The proposed equipment arrangement is shown in Figure 9.1-5. New monitoring equipment for SO_2, HCl, O_2, and CO_2 for each combustor is also included. Downtime is expected to be approximately one month for each combustor.

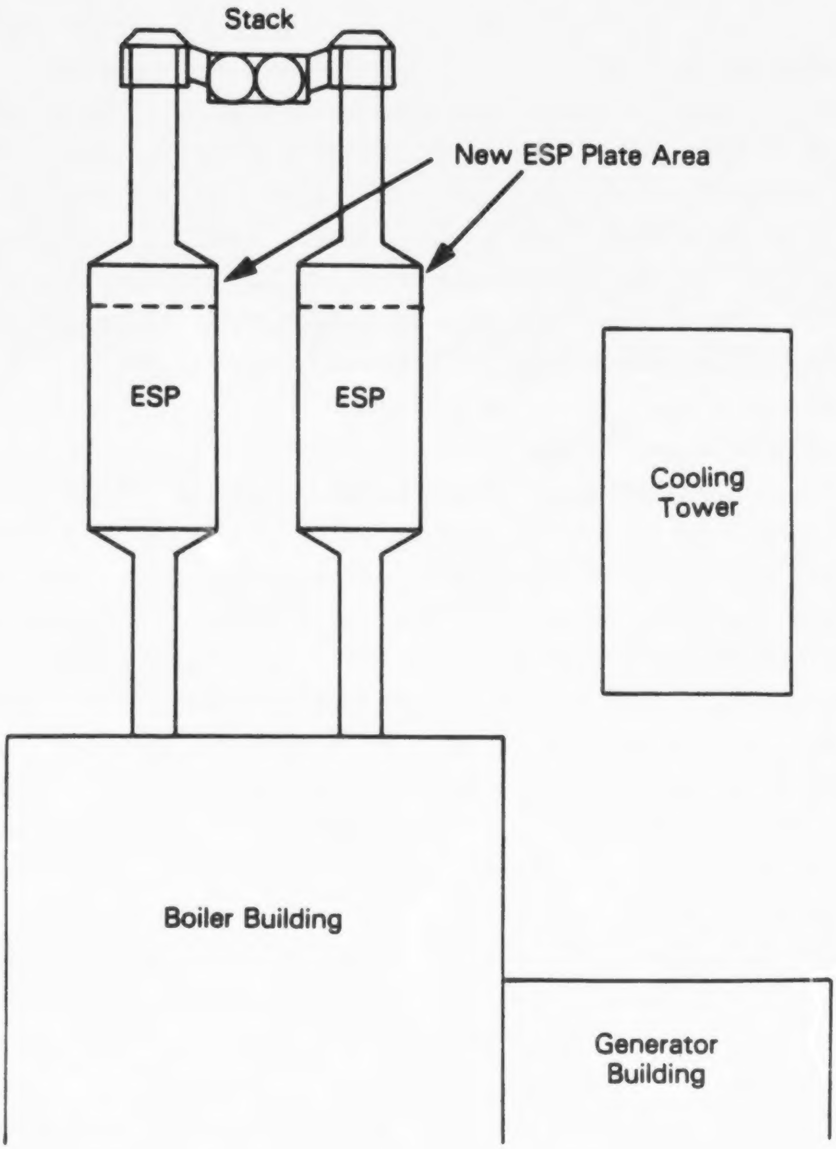

Figure 9.1-4. Particulate Control Equipment Arrangement

TABLE 9.1-6. PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS (Two units of 250 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
PM Control[a]	
Upgrade Costs	1,150
Access/Congestion Cost	288
New Flue Gas Ducting[a]	
Ducting Costs	34
Access/Congestion Cost	9
Other Equipment	
Fan	0
Stacks	0
Demolition/Relocation	0
Total	1,480
Indirect Costs and Contingencies	506
Monitoring Equipment	0
TOTAL CAPITAL COST	1,990
DOWNTIME COST	588
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	338

[a] Based on moderate access/congestion.

TABLE 9.1-7. PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROLS
(Two units of 250 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	20
Electricity	5
Waste Disposal	1
Monitors	0
Total	26
INDIRECT COSTS:	
Overhead	12
Taxes, Insurance, and Administration	80
Capital Recovery and Downtime	338
Total	430
TOTAL ANNUALIZED COST	456

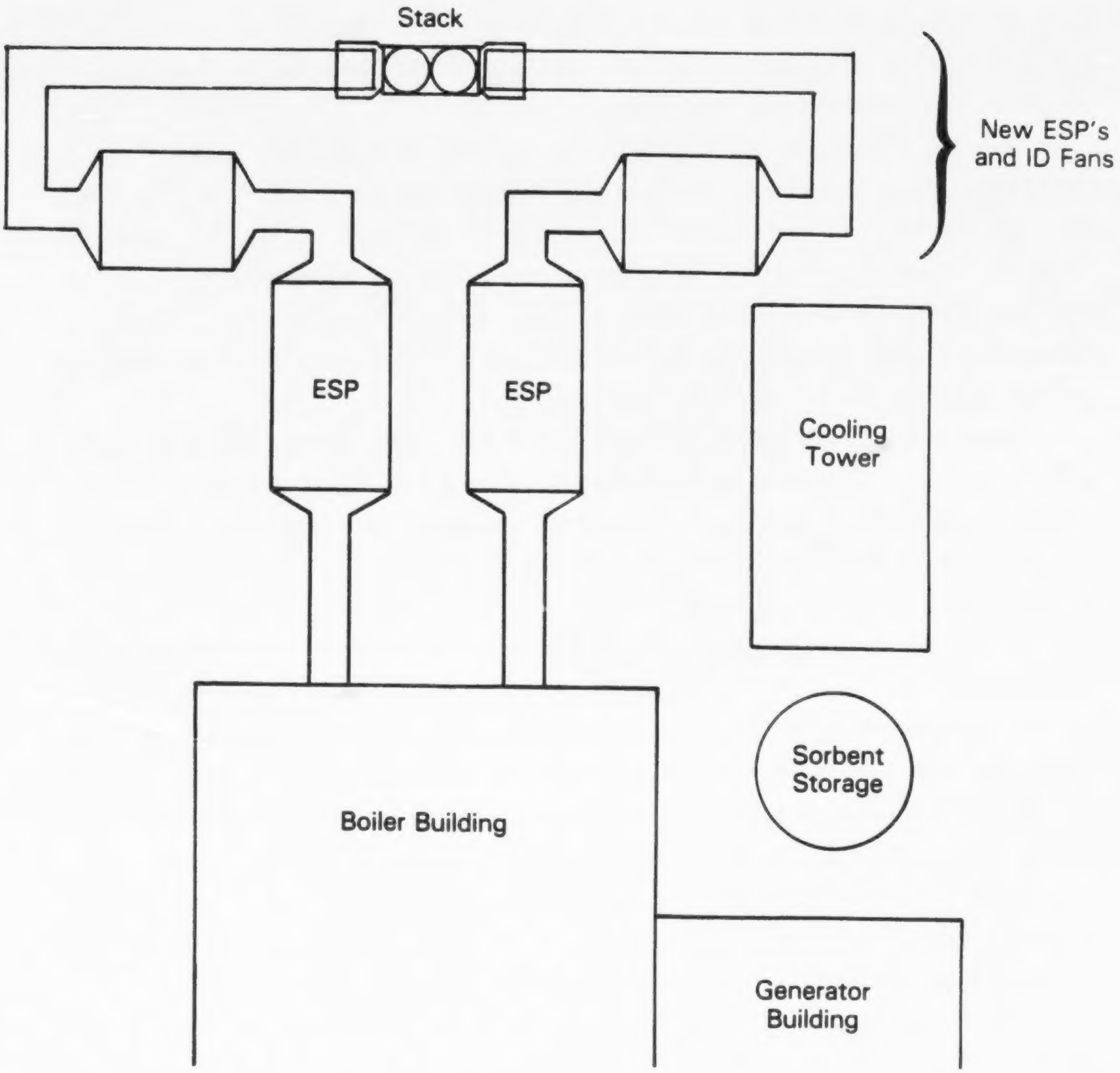

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Figure 9.1-5. Dry Sorbent Injection Equipment Arrangement

9.1.5.2 Environmental Performance. Total CDD/CDF emissions are expected to be reduced 75 percent from baseline levels or to 50 dscm, whichever is higher. Acid gas emission reductions are expected to be 80 percent for HCl and 40 percent for SO_2. Particulate matter emissions will be reduced from 0.03 gr/dscf to 0.01 gr/dscf. Additional collected fly ash and sorbent will add 2,950 tons per year of solid waste to the baseline disposal requirements for the plant.

9.1.5.3 Costs. The capital cost requirements for dry sorbent injection are presented in Table 9.1-8. Total capital cost is $4,140,000. Most of the cost is associated with equipment for particulate and temperature control. A moderate access and congestion level was assumed for all new equipment except the ducts containing the spray nozzles. Since these ducts pass through the boiler building wall, a high access/congestion factor was applied to their direct cost.

Annual costs are presented in Table 9.1-9. The major operating costs are for sorbent purchase and maintenance of monitoring instruments. The largest annual cost is annualized capital recovery and downtime. Total annual cost is estimated to be $1,560,000.

9.1.6 Best Acid Gas Control

9.1.6.1 Description of Modifications. To achieve greatest reductions in CDD/CDF, HCl, and SO_2, a spray dryer with fabric filter will be installed on each combustor. The existing ESP's will not be demolished, but will be by-passed and left in place. A total of 300 feet of new duct will be used to connect the new equipment between the boilers' outlets and the existing stack. The proposed equipment arrangement is shown in Figure 9.1-6.

Lime slurry will be introduced into the spray dryers at a calcium-to-acid gas molar ratio of 2.5:1. Water in the lime slurry equivalent to 7 gpm is needed to cool the gas stream from 450°F to 300°F.

The plant lime receiving, storage, and slurry preparation area is also shown in Figure 9.1-6. Each fabric filter will have an effective cloth area of 10,600 square feet (net air-to-cloth ratio of 4:1). The increased pressure drop of the fabric filters relative to the existing ESP's will require replacement of the ID fans. New monitoring instruments for HCl,

TABLE 9.1-8. PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA (Two units of 250 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas Control[a]	
Equipment	349
Access/Congestion Cost	35
Particulate and Temperature Control[b]	
Equipment	1,580
Access/Congestion Cost	320
New Flue Gas Ducting[a]	
Ducting Cost	71
Access/Congestion Costs	24
Other Equipment	
Fans	170
Stacks	0
Demolition/Relocation	0
Total	2,550
Indirect Costs and Contingencies	1,080
Monitoring Equipment[c]	514
TOTAL CAPITAL COST	4,140
DOWNTIME COST	588
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	622

[a] Based on moderate access/congestion.

[b] Based on high access/congestion for temperature control ductwork.

[c] Turnkey.

TABLE 9.1-9. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA (Two units for 250 tpd each)

Item	Costs ($1000)
DIRECT COSTS:	
Operating Labor	60
Supervision	16
Maintenance Labor	26
Maintenance Materials	47
Electricity	30
Water	2
Lime	181
Waste Disposal	74
Monitors	206
Total	642
INDIRECT COSTS:	
Overhead	89
Taxes, Insurance, and Administration	145
Capital Recovery and Downtime	622
Total	856
TOTAL ANNUALIZED COST	1,500

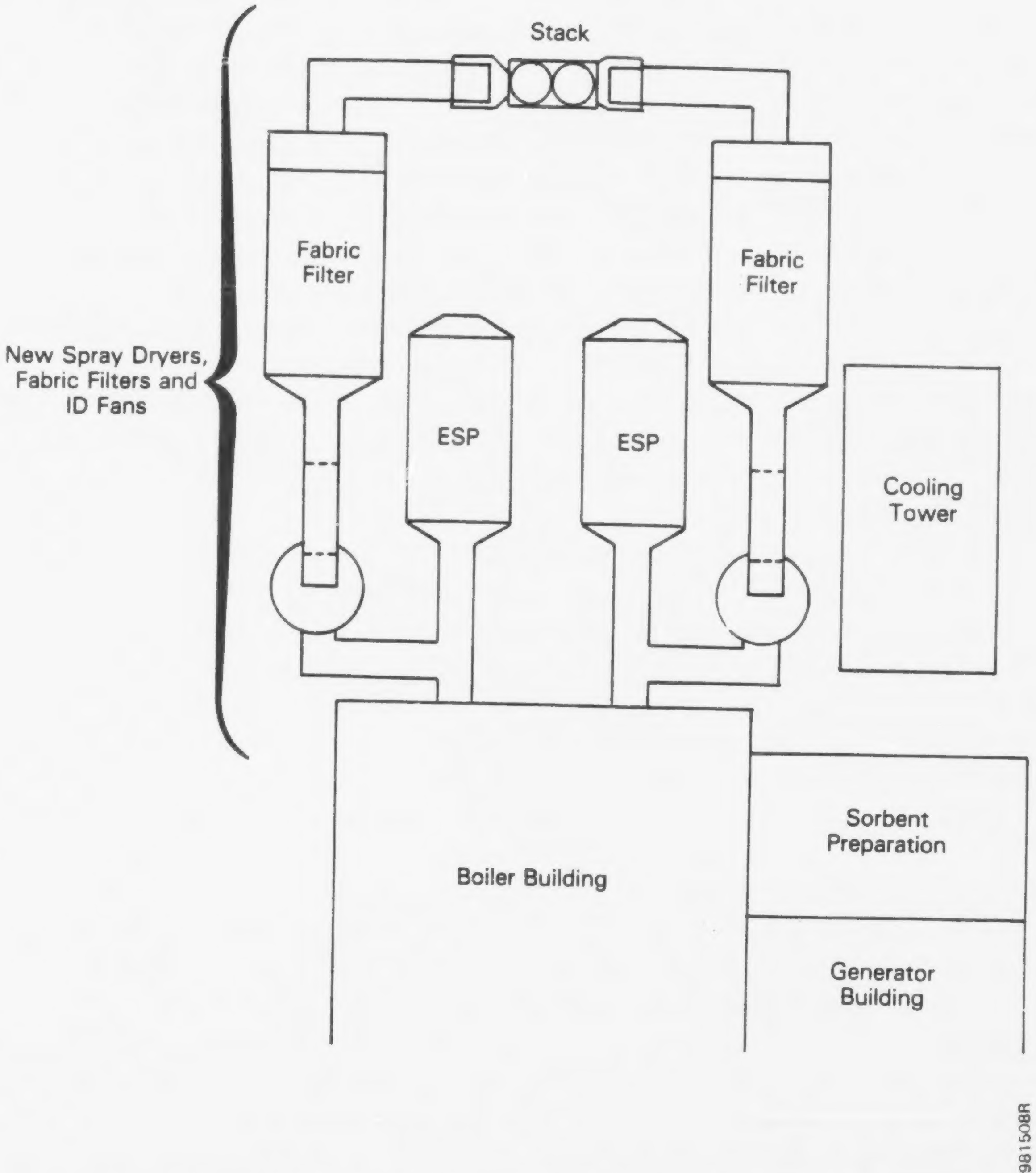

Figure 9.1-6. Spray Dryer/Fabric Filter Equipment Arrangement

SO_2, CO_2, O_2, and opacity will also be installed. Downtime is expected to be one month for each combustor for ductwork and tie-ins.

9.1.6.2 Environmental Performance. Reductions in CDD/CDF emissions of 99 percent or to 5 dscm (whichever is higher) are expected. Emissions of particulate matter will be reduced to 0.01 gr/dscf. Acid gas emissions will be reduced 90 percent for SO_2 and 97 percent for HCl. Solid waste in the form of recovered sorbent and additional recovered fly ash will add 2,590 tons per year to the plant disposal requirements.

9.1.6.3 Costs. Capital costs for installing the spray dryer/fabric filter systems are shown in Table 9.1-10. Total capital cost is $10,600,000; the major capital item is purchased equipment. A moderate access and congestion factor was used for all new equipment. Annual costs are shown in Table 9.1-11. The largest annual costs are for maintenance materials including bag replacement, and for annualized capital recovery and downtime. Maintenance cost for process monitors is also significant. Total annual cost is estimated at $2,960,000 per year.

9.1.7 Summary of Control Options

9.1.7.1 Description of Control Options. The control technologies described in Sections 9.1.2 through 9.1.6 have been combined into the seven retrofit emission control options previously described in Section 3.0. Table 9.1-12 presents the combination of combustion, temperature, particulate, and acid gas control technology used for each of the control options. It should be noted that since the model plant already achieves good PM control at baseline, Options 1 and 2 are identical.

9.1.7.2 Environmental Performance. The performance of each control option is summarized in Table 9.1-13. For each pollutant, the table presents both the pollutant concentrations and emissions. The greatest reduction in CDD/CDF emissions is achieved by addition of the spray dryer/fabric filter systems; the next most effective measure for control of CDD/CDF is combustor modification. The lowest overall emissions of CDD/CDF result from the implementation of both of these technologies together. Dry sorbent injection is almost as effective for CDD/CDF control as combustor modifications. Both sorbent addition technologies negatively impact solid waste disposal requirements slightly.

TABLE 9.1-10. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 250 tpd each)

Item		Cost ($1000)
DIRECT COSTS:		
Acid Gas Control		
Equipment		5,040
Access/Congestion Cost		950
New Flue Gas Ducting		
Ducting Cost		102
Access/Congestion Cost		26
Other Equipment		
Fans		183
Stacks		0
Demolition/Relocation		0
	Total	6,300
Indirect Costs		2,080
Contingency		1,670
Monitoring Equipment[a]		573
TOTAL CAPITAL COST		10,600
DOWNTIME COST		588
ANNUALIZED CAPITAL RECOVERY AND CONTINGENCIES		1,470

[a] Turnkey.

TABLE 9.1-11. PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Two units of 250 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	96
Supervision	14
Maintenance Labor	53
Maintenance Materials	154[a]
Electricity	116
Compressed Air	16
Water	4
Lime	150
Waste Disposal	97
Monitors	215
Total	913
INDIRECT COSTS:	
Overhead	173
Taxes, Insurance, and Administration	402
Capital Recovery and Downtime	1,470
Total	2,050
TOTAL ANNUALIZED COST	2,960

[a] Includes bag replacement costs of $28,000.

TABLE 9.1-12. SUMMARY OF CONTROL OPTIONS FOR ROTARY WATERWALL COMBUSTOR

Control Option Description	Combustion Modifications	Temperature Control	Particulate Control		Acid Gas Control		
			Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control	X						
2. Good PM Control with Combustion Control and Temperature Control	X						
3. Best PM Control and Combustion and Temperature Control				X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 9.1-13. ENVIRONMENTAL PERFORMANCE SUMMARY FOR ROTARY WATERWALL ROTARY MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 250 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	2000	400	400	400	500	100	20	5
Mg/yr	1.3E-3	2.6E-4	2.6E-4	2.6E-4	3.2E-4	6.5E-5	1.3E-5	3.2E-6
% Reduction vs. Baseline	--	80	80	80	75	95	99	99
CO Emissions								
(ppmv)	100	100	100	100	100	100	100	100
Mg/yr	81	81	81	81	81	81	81	81
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01
Mg/yr	49	49	49	16	16	16	16	16
% Reduction vs. Baseline	--	0	0	67	67	67	67	67
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	370	370	370	370	222	222	35	35
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	528	528	528	528	106	106	15	15
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	150	150	150	150	159	159	162	162
Mg/yr	45,500	45,500	45,500	45,500	48,500	48,500	48,970	48,970
% Increase vs. Baseline	--	0	0	0	7	7	8	8

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Normal and Standard conditions are 1 atmosphere and 70°F.

9.1.7.3 Costs. The total annualized cost of each option is presented in Table 9.1-14. The cost of control options increases as the level of control increases. Combustion control combined with acid gas control technologies increases CDD/CDF control substantially (about 80 percent) with very little additional cost. This is because the major cost of combustion retrofit is downtime, and the downtime for the acid gas APCD retrofit is longer than for the combustion modifications.

9.1.7.4 Energy Impacts. Table 9.1-15 presents a summary of the energy impacts associated with the control options. The electrical use figures take into account the savings realized by not operating the existing ESP. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and are used under baseline operation.

TABLE 9.1-14. COST SUMMARY FOR ROTARY WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 250 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	295	295	2,290	4,140	4,440	10,600	10,900
Downtown Cost	441	441	588	588	588	588	588
Annualized Capital and Downtime Cost	97	97	377	622	661	1,470	1,510
Direct O&M Cost	0	0	26	642	642	913	913
Total Annual Cost	109	152	507	1,500	1,550	2,960	3,010
Cost Effectiveness ($/ton MSW)	0.65	0.91	3.04	8.98	9.28	17.80	18.10
Facility Downtime (Months)	0.75	0.75	1	1	1	1	1
Total Compliance Time (Months)	5	5	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

TABLE 9.1-15. ENERGY IMPACTS FOR ROTARY WATERWALL COMBUSTOR MODEL PLANT CONTROL OPTIONS[a]
(Two units of 250 tpd each)

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	102	0
4	672	0
5	672	0
6	2,520[b]	0
7	2,520[b]	0

[a] Increase from baseline consumption.

[b] Excludes the electrical credit of not operating the ESP's.

9.2 REFERENCES

1. Schindler, P., Energy and Environmental Research Corporation, and Lamb, L., Radian Corporation. Trip Report - Retrofit Control Site Evaluation at the Bay County, Florida Waste-to-Energy Facility. March 30, 1988.

10.0 MODEL PLANTS REPRESENTING PROJECTED 111(d) FACILITIES

In addition to the estimated 160 MWC's currently operating, there are at least another 110 that will commence construction by 1989 and therefore be subject to the 111(d) regulations. This population was examined and each facility was assigned to one of the 12 model plants presented in Section 4.0 through 9.0 when appropriate. Where differences between the population of planned facilities and the existing 111(d) model plants were identified, new model plants were developed. A list of these facilities and the model plants they have been assigned to is presented in a separate memorandum. Sections 10.1 through 10.5 present the case study summaries for the additional five model plants developed to represent planned 111(d) facilities.

10.1 LARGE MODULAR EXCESS AIR COMBUSTOR

10.1.1 Description of the Model Plant

10.1.1.1 Combustor Design and Operation. The model plant presented in this section was selected as representative of six planned 111(d) plants that would commence construction by November 1989 and be subject to the Section 111(d) guidelines currently being developed. Although this model plant is similar in design to the modular excess-air plant presented in Section 8.1, this model is somewhat larger. This reflects the relative increase in capacity represented by the projected excess-air MWC's. The model plant data are shown in Table 10.1-1.

The model plant consists of three units, each with a rated capacity of 140 tpd and based on the Enercon/Vicon design. The units burn 100 percent municipal solid waste, 24-hours/day, 7-days/week. Each unit has both primary and secondary combustion chambers which manifold into a single tertiary duct where burning is completed prior to the flue gases entering a waste heat boiler. The boiler reduces the flue gas temperature from 1400°F to 450°F before entering the air pollution control equipment.

Fuel feeding and combustion air supplies are identical to those of the modular excess-air plant described in section 8.1. Excess air levels at the boiler outlet are assumed to be 50 percent. Flue gas flowrates are approximately 40,100 dscfm at the boiler exit. CO and O_2 monitors are located at the secondary chamber exit. Temperatures are measured at the

TABLE 10.1-1 MODEL PLANT BASELINE DATA FOR LARGE MODULAR EXCESS-AIR COMBUSTOR

Combustor:	
Type	- Modular Excess-air
Number of Combustors	- 3
Combustor Unit Capacity	- 140 tpd each
Plant Capacity	- 420 tpd
Emission Controls:	
Type	- Electrostatic Precipitator
Number of ESP's	- 1
Number of Fields	- 2
Inlet Temperature	- 450°F
Collection Efficiency	- 97.5 percent
Gas Flow	- 82,000 acfm
Total Plate Area	- 24,200 ft^2
SCA at 82,000 acfm and 450°F	- 295
Emissions:[a]	
CDD/CDF (tetra-octa)	- 200 ng/dscm
PM (stack)	- 0.05 gr/dscf[b]
CO	- 50 ppmv
HCl	- 500 ppmv
SO_2	- 200 ppmv
Stack Parameters:	
Height	- 70 ft
Diameter	- 8.0 ft
Operating Data:	
Remaining Plant Life	- $\geq$ 20 years
Annual Operating Hours	- 8,000 hours
Annual Operating Cost	- $3,810,000

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[a] All emissions are dry, corrected to 7 percent O_2. Standard and Normal conditions are both 70°F and 1 atmosphere.

[b] Inlet PM emissions to the ESP are 2.0 gr/dscf at 7 percent O_2.

exit of the primary and secondary chambers, and at the boiler inlet and outlet. An auxiliary fuel burner is located in the primary combustion chamber for use during process start-up and during episodes of low temperatures.

10.1.1.2 Emission Control System Design and Operation. As with the model plant described in Section 8.1, the model plant here is equipped with a single 2-field ESP controlling particulate matter emissions to 0.05 gr/dscf at 7 percent O_2. Since all three combustors are ducted to a single boiler and ESP, a single stack is also assumed. The model plant ID fan is located downstream of the ESP. A plot plan of the model plant is shown in Figure 10.1-1.

10.1.1.3 Environmental Baseline. Table 10.1-1 also presents baseline emissions data for the model plant. Baseline emissions are the same as presented for the modular excess air model plant presented in Section 8.1. The combustion process is assumed to reduce incoming waste 90 percent by volume and 70 percent by weight.

10.1.2 Good Combustion Control

The model plant has good combustion practices in place. This is verified by the low uncontrolled levels of CDD/CDF and CO emissions. Under normal operating conditions the combustor achieves $1800^{0}F$, and good mixing is in place. Monitoring of temperature, oxygen, and CO is also in place. Due to adequate heat removal through the boiler, the exhaust gas temperature is $450^{0}F$. As a result, there is no need for further flue gas temperature reduction prior to the air pollution control equipment, and the potential for formation of CDD/CDF in the ESP is minimized. Based on this assessment there are no combustion retrofits required for the model plant.

10.1.3 Best Particulate Control

The ESP in place on the model plant reduces PM by 97.5 percent, from 2.0 gr/dscf to 0.05 gr/dscf corrected to 7 percent O_2. Therefore, the baseline PM emission rate is equal to the rate identified with good control (0.05 gr/dscf), and no plant modifications will be required for this control level.

10.1.3.1 Description of Modifications. To achieve best particulate matter control (0.01 gr/dscf emission rate) will require an ESP with 34,500 square feet of collection area. Therefore, an additional

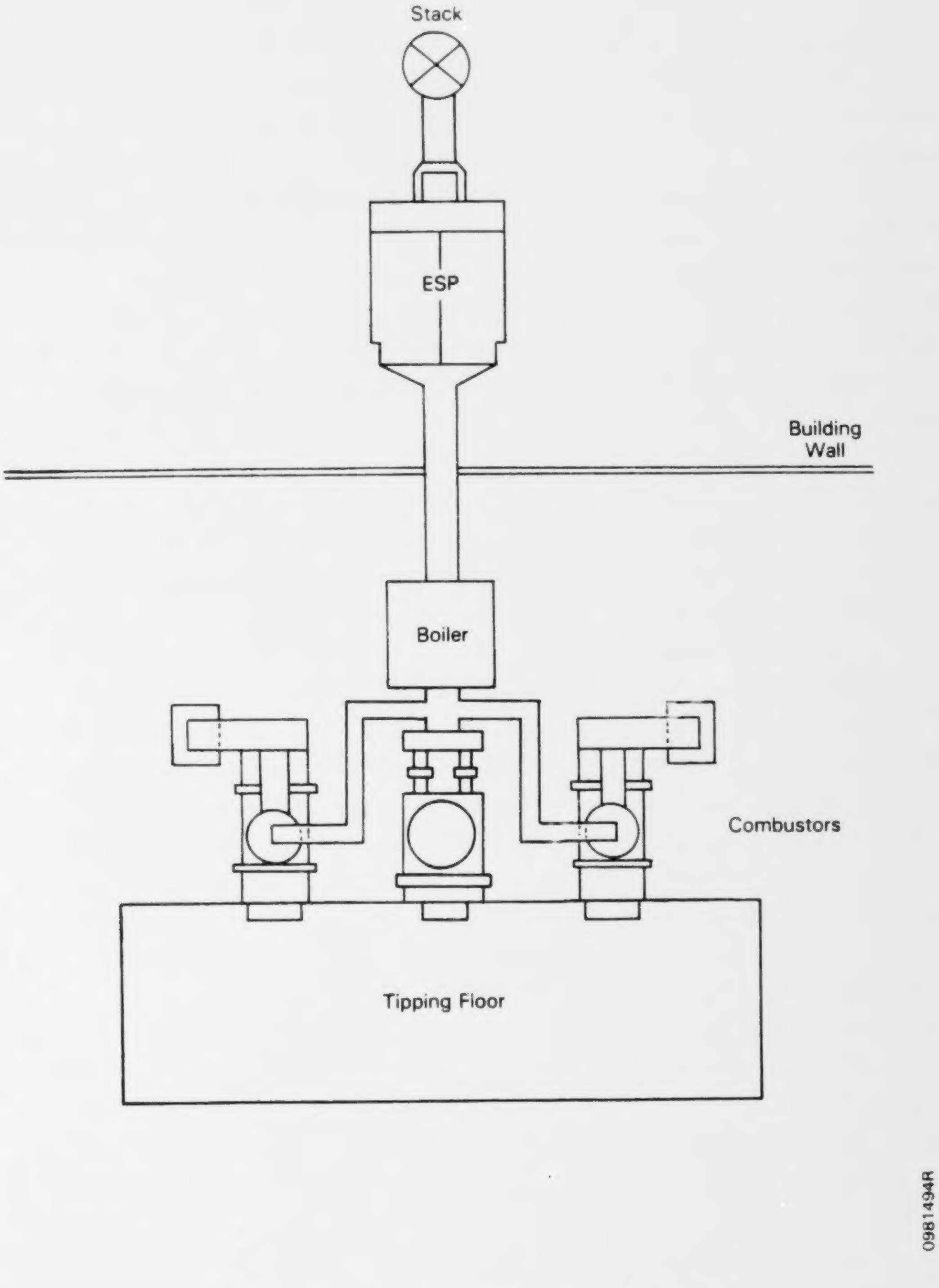

Figure 10.1-1. Plot Plan of Model Plant

10,300 square feet will be added to the model plant ESP. The additional area will be installed as a separate single-field ESP in series with the existing ESP. A hundred feet of new duct and a new ID fan will be required. The existing stack will continue to be used. A plot plan of the proposed equipment arrangement is shown in Figure 10.1-2. No new monitoring equipment will be required. Downtime will affect both combustors at once and is estimated at one month for ductwork tie-in.

10.1.3.2 Environmental Performance. Particulate matter emissions will be reduced from 0.05 gr/dscf to 0.01 gr/dscf. The increased fly ash recovery will add 55 tons per year to the baseline solid waste disposal requirements for the plant.

10.1.3.3 Costs. Capital cost requirements for best particulate control are shown in Table 10.1-2. The major cost item is the particulate control equipment. Total capital requirement is $1,400,000. Annual costs are presented in Table 10.1-3, and are dominated by annualized capital recovery and downtime. Total annual costs are expected to be $327,000 per year.

10.1.4 Good Acid Gas Control

10.1.4.1 Description of Modifications. For good acid gas and CDD/CDF control, hydrated lime sorbent will be injected into the flue gas duct before the ESP. The lime sorbent will be fed at a molar ratio 2:1 (calcium to acid gas) for a rate of 475 lb/hr with both combustors operating. Additional equipment for sorbent injection will include a sorbent storage silo, a pneumatic sorbent transfer system, a sorbent feed bin, and pneumatic injection nozzles. To cool the flue gas from 450^{0}F to 350^{0}F, spray nozzles, also located in the duct before the ESP, will introduce 8 gpm of water. Fifty feet of new duct will be fabricated containing the water and sorbent nozzles.

A total of 39,900 square feet of ESP collection area will be required to collect the sorbent and fly ash to an emission level of 0.01 gr/dscf. Therefore, an additional 15,700 square feet of collection area will be added to the model plant ESP. The additional area will be installed as a separate single-field ESP in series with the existing ESP. Installation of the new ESP will also require 100 feet of new duct and a new ID fan. The proposed

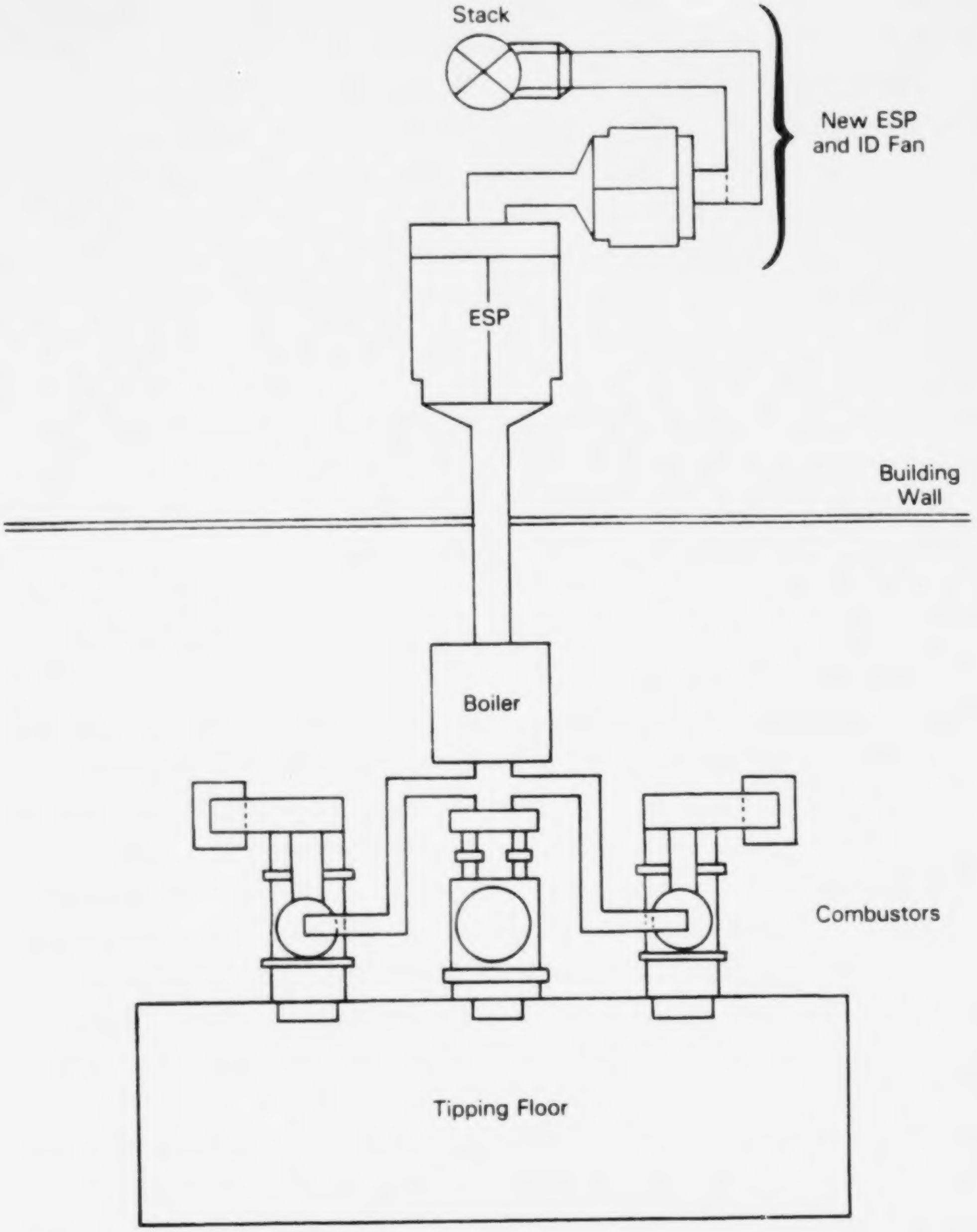

Figure 10.1-2. Plot Plan of Particulate Control Equipment

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TABLE 10.1-2 PLANT CAPITAL COST FOR PARTICULATE MATTER CONTROLS
(Three units of 140 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
PM Control[a]	
Upgrade Costs	671
Access/Congestion Cost	168
New Flue Gas Ducting[a]	
Ducting Costs	45
Access/Congestion Cost	11
Other Equipment	
Fan	152
Stack	0
Demolition/Relocation	0
Total	1,050
Indirect Costs and Contingencies	357
Monitoring Equipment	0
TOTAL CAPITAL COST	1,400
DOWNTIME COST	432
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	242

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[a] Based on moderate access/congestion.

TABLE 10.1-3 PLANT ANNUAL COST FOR PARTICULATE MATTER CONTROLS
(Three units of 140 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	0
Supervision	0
Maintenance Labor	0
Maintenance Materials	14
Electricity	6
Waste Disposal	1
Monitors	0
Total	21
INDIRECT COSTS:	
Overhead	8
Taxes, Insurance, and Administration	56
Capital Recovery and Downtime	242
Total	305
TOTAL ANNUALIZED COST	327

equipment arrangement is shown in Figure 10.1-3. New monitoring equipment for SO_2, HCl, O_2 and CO_2 is also included. Downtime is estimated at one month.

10.1.4.2 Environmental Performance. CDD/CDF emissions are expected to be reduced to 25 percent of inlet levels or to 50 ng/dscm, whichever is greater. Acid gas emission reductions are expected to be 80 percent for HCl and 40 percent for SO_2. Particulate matter emissions will be reduced to 0.01 gr/dscf. Additional collected fly ash and sorbent will add 2,510 tons per year of solid waste to the baseline disposal requirements for the plant.

10.1.4.3 Costs. Capital cost requirements for dry sorbent injection are presented in Table 10.1-4. Total capital cost is $2,790,000. Most of the cost is associated with new equipment for particulate and temperature control. A moderate access and congestion level is assumed for all equipment except the duct containing the spray nozzles. Since this duct passes through the building wall, a high access/congestion factor was applied to the direct cost.

Annual costs are presented in Table 10.1-5. The major operating costs are for lime purchase and monitoring equipment maintenance. The largest annual cost is annualized capital recovery and downtime. Total annual cost is estimated to be $999,000.

10.1.5 Best Acid Gas Control

10.1.5.1 Description of Modifications. To achieve greater reductions in CDD/CDF, HCl, and SO_2, a spray dryer/fabric filter system will be installed. The existing ESP will not be demolished, but will be bypassed and left in place. A total of 200 feet of new duct will be used to connect the new equipment between the boiler outlet and the existing stack. The proposed equipment arrangement is shown in Figure 10.1-4.

Lime slurry will be introduced into the spray dryer at a calcium-to-acid gas molar ratio of 2.5:1. Water in the lime slurry equivalent to 12 gpm is needed to cool the gas stream from $450^{\circ}F$ to $300^{\circ}F$.

The lime receiving, storage and slurry preparation area is also shown in Figure 10.1-4. The fabric filter will have 17,800 square feet of effective cloth area (net air-to-cloth ratio of 4:1). The increased pressure drop of

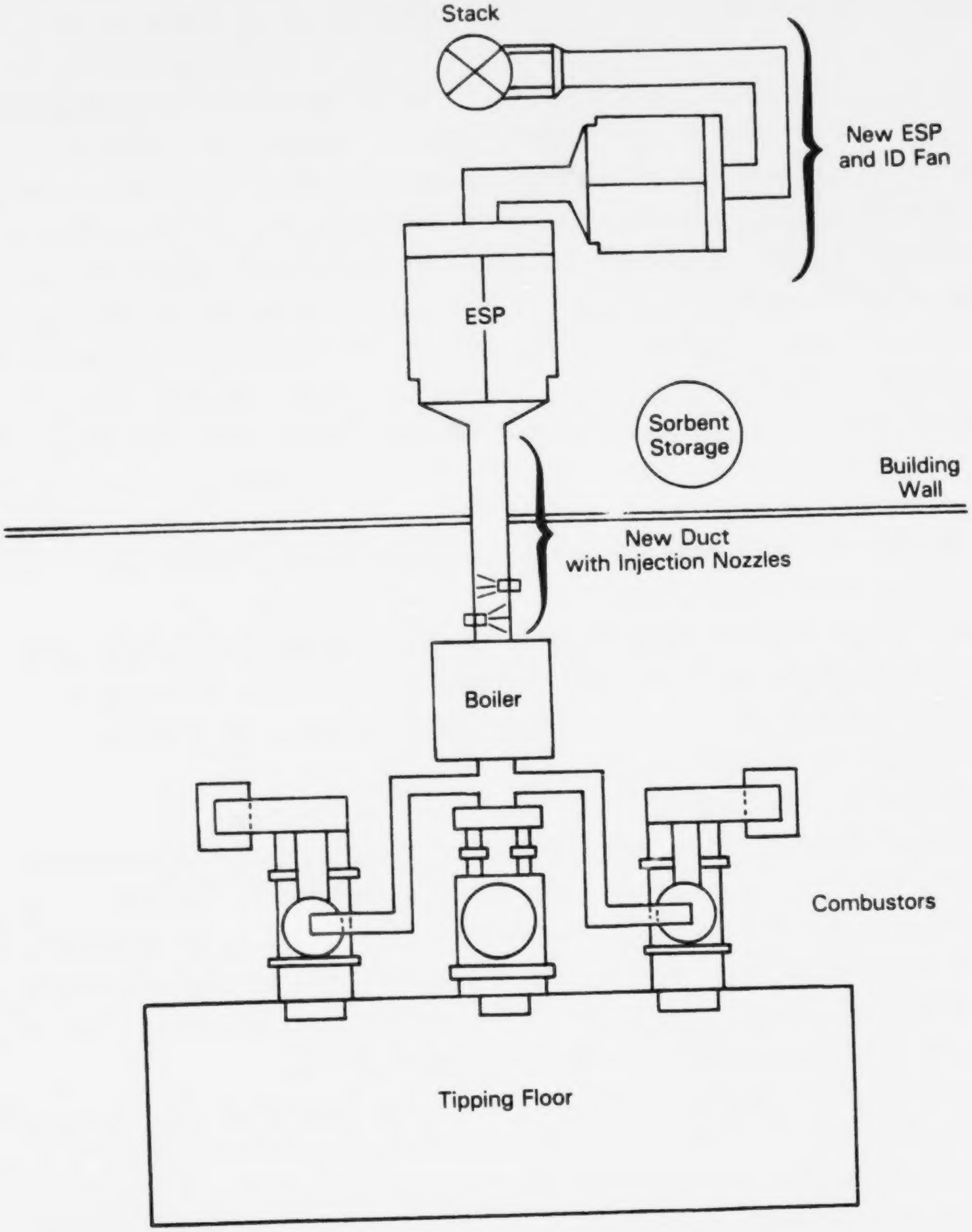

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Figure 10.1-3. Plot Plan of Dry Sorbent Injection Equipment Arrangement

TABLE 10.1-4 PLANT CAPITAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA (Three units of 140 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Acid Gas Control[a]	
Equipment	331
Access/Congestion Cost	33
Particulate and Temperature Control[b]	
Equipment	974
Access/Congestion Cost	203
New Flue Gas Ducting[a]	
Ducting Cost	43
Access/Congestion Costs	10
Other Equipment	
Fans	140
Stacks	0
Demolition/Relocation	0
Total	1,730
Indirect Costs and Contingencies	801
Monitoring Equipment[c]	257
TOTAL CAPITAL COST	2,790
DOWNTIME COST	432
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME	423

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[a] Based on moderate access/congestion.

[b] Based on high access/congestion for temperature control ductwork.

[c] Turnkey.

TABLE 10.1-5. PLANT ANNUAL COST FOR DRY SORBENT INJECTION WITH ADDITIONAL ESP COLLECTION AREA
(Three units of 140 tpd each)

Item	Cost ($1000)
DIRECT COSTS:	
Operating Labor	30
Supervision	5
Maintenance Labor	14
Maintenance Materials	36
Electricity	21
Water	2
Lime	152
Waste Disposal	63
Monitors	103
Total	425
INDIRECT COSTS:	
Overhead	50
Taxes, Insurance, and Administration	101
Capital Recovery and Downtime	423
Total	574
TOTAL ANNUALIZED COST	999

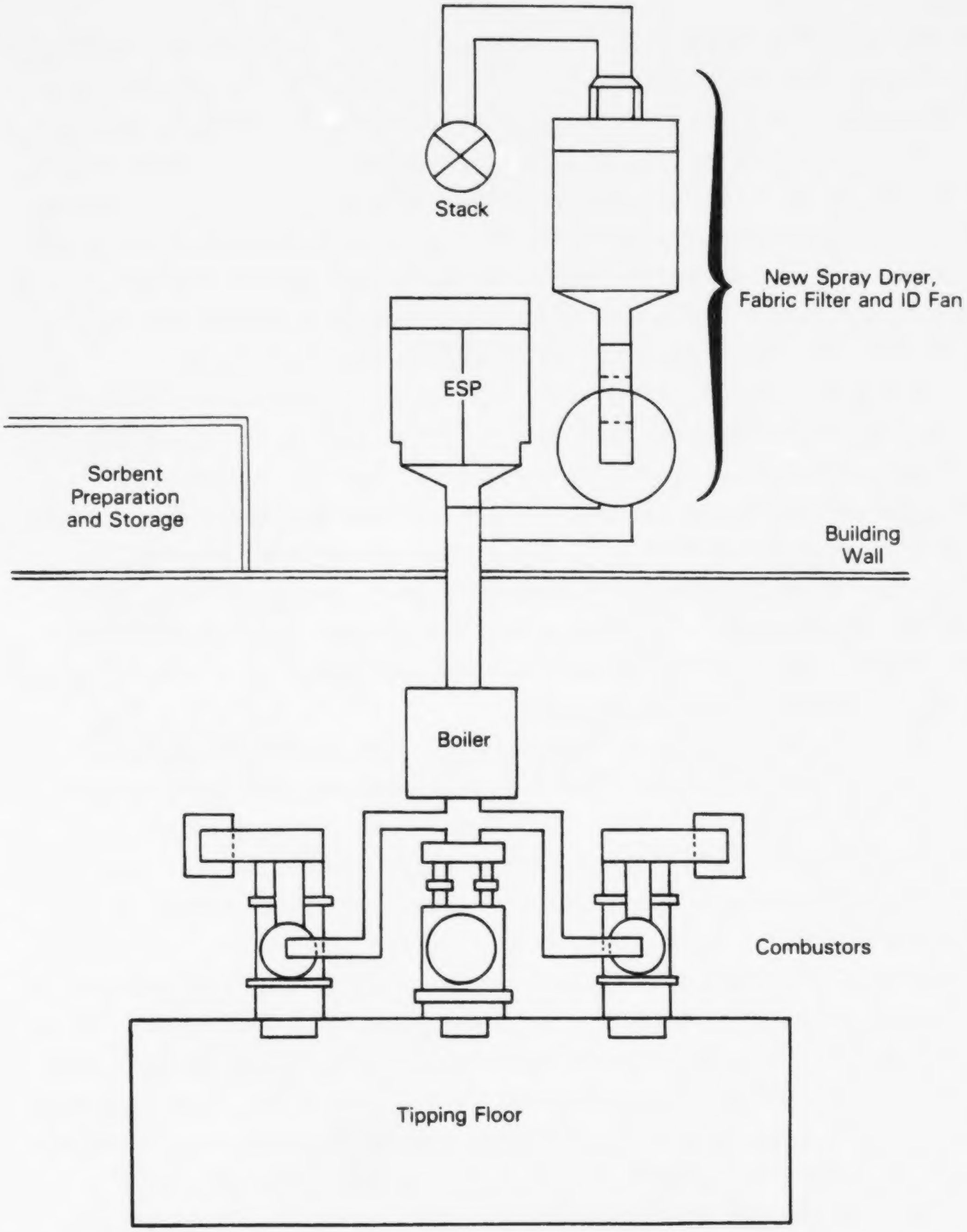

Figure 10.1-4 Plot Plan of Spray Dryer/Fabric Filter Retofit Equipment Arrangement

the fabric filter relative to the existing ESP will require replacement of the ID fan. New monitoring equipment for HCl, SO_2, CO_2, O_2 and opacity will be installed. Downtime is expected to be one month for ductwork tie-ins.

10.1.5.2 Environmental Performance. CDD/CDF emission reduction of 99 percent or to 5 ng/dscm (whichever gives higher emissions) is expected. Emissions of particulate matter will be reduced to 0.01 gr/dscf. Acid gas emissions will be reduced 70 percent for SO_2 and 90 percent for HCl. Solid waste in the form of additional fly ash and recovered sorbent will add 2,210 tons per year to the plant solid waste disposal requirements.

10.1.5.3 Costs. Capital costs for installing a spray dryer/fabric filter system are shown in Table 10.1-6. Total capital cost is $6,950,000. The major capital cost is for the purchased equipment. A moderate access/congestion factor was applied to all direct equipment costs. Annual costs are shown in Table 10.1-7. The largest annual costs are for maintenance materials, including bag replacement, and annualized capital recovery and downtime. Maintenance cost for monitors is also significant. Total annual cost is estimated at $1,950,000 per year.

10.1.6 Summary of Control Options

10.1.6.1 Description of Control Costs. The control technologies described in the previous sections have been combined into seven retrofit emission control options. Table 10.1-8 summarizes the combustion, particulate, temperature, and acid gas control technologies described in Sections 10.1.2 through 10.1.5 that were combined for each of the control options described in Section 3.0.

It should be noted that since the model plant already achieves moderate PM control at baseline, Options 1 and 2 are identical. Also, since the model plant achieves good combustion at baseline, Options 1 and 2 are equivalent to baseline, Options 4 and 5 are identical, and Options 6 and 7 are identical.

10.1.6.2 Environmental Performance. The performance of each control option is summarized in Table 10.1-9. For each pollutant, the table presents both the pollutant concentrations and emissions. The greatest emission reductions of acid gases, particulate matter, and CDD/CDF all are achieved with the spray dryer/fabric filter system. The next most effective control for all these pollutants is dry sorbent injection. Both sorbent

TABLE 10.1-6. PLANT CAPITAL COST FOR SPRAY DRYER WITH FABRIC FILTER (Three units of 140 tpd each)

Item		Cost ($1000)
DIRECT COSTS:		
Acid Gas Control		
Equipment		3,130
Access/Congestion Cost		781
New Flue Gas Ducting		
Ducting Cost		89
Access/Congestion Cost		22
Other Equipment		
Fans		151
Stacks		0
Demolition/Relocation		0
	Total	4,170
Indirect Costs		1,380
Contingency		1,110
Monitoring Equipment[a]		286
TOTAL CAPITAL COST		6,950
DOWNTIME COST		432
ANNUALIZED CAPITAL RECOVERY AND DOWNTIME		970

[a] Turnkey.

TABLE 10.1-7 PLANT ANNUAL COST FOR SPRAY DRYER WITH FABRIC FILTER
(Two units of 100 tpd each)

Item		Cost ($1000)
DIRECT COSTS:		
Operating Labor		48
Supervision		7
Maintenance Labor		26
Maintenance Materials		106[a]
Electricity		93
Compressed Air		13
Water		3
Lime		126
Waste Disposal		82
Monitors		107
	Total	613
INDIRECT COSTS:		
Overhead		99
Taxes, Insurance, and Administration		266
Capital Recovery and Downtime		970
	Total	1,340
TOTAL ANNUALIZED COST		1,950

[a] Includes bag replacement costs of $23,000.

TABLE 10.1-8 SUMMARY OF CONTROL OPTIONS FOR LARGE MODULAR EXCESS-AIR COMBUSTOR

			Particulate Control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional Plant Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion Control							
3. Best PM Control and Combustion and Temperature Control				X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 10.1-9 ENVIRONMENTAL PERFORMANCE SUMMARY FOR LARGE MODULAR EXCESS-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 140 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
CDD/CDF Emissions								
(ng/dscm)	200	200	200	200	50	50	5	5
Mg/yr	1.09E-4	1.09E-4	1.09E-4	1.09E-4	2.7E-5	2.7E-5	1.3E-6	2.7E-6
% Reduction vs. Baseline	--	0	0	0	75	75	98	98
CO Emissions								
(ppmv)	50	50	50	50	50	50	50	50
Mg/yr	31.5	31.5	31.5	31.5	31	31.5	31.5	31.5
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	62.1	62.1	62.1	12.4	12.4	12.4	12.4	12.4
% Reduction vs. Baseline	--	0	0	80	80	80	80	80
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	305	305	305	305	183	183	29	29
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	417	417	417	417	84	84	13	13
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	126	126	126	126	134	134	136	136
Mg/yr	38,100	38,100	38,100	38,150	40,400	40,400	41,100	41,100
% Increase vs. Baseline	--	0	0	0.1	6	6	8	8

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Standard and Normal conditions are both 1 atmosphere and 70°F.

addition technologies increase solid waste slightly (less than 10 percent over baseline). No combustion modifications were made, so CO emissions remain unchanged at 50 ppm for all options.

10.1.6.3 Costs. The total annualized cost of each option is presented in Table 10.1-10. The most costly control option is the spray dryer/fabric filter installation, at a capital cost of $2,270,000. Overall, costs are higher for higher levels of control.

10.1.6.4 Energy Impacts. Table 10.1-11 presents a summary of the energy impacts associated with the control options. The energy use figures are incremental use; savings realized by not operating the existing ESP are taken into account. There is no increase in auxiliary fuel use because auxiliary burners are already in place on the model plant and are used under baseline operation.

TABLE 10.1-10 COST SUMMARY FOR THE LARGE MODULAR EXCESS-AIR MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Three units of 140 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	1,400	2,790	2,790	6.950	6,950
Downtime Cost	0	0	432	432	432	432	432
Annualized Capital and Downtime Cost	0	0	242	423	423	970	970
Annual O&M Cost	0	0	21	425	425	613	613
Total Annual Cost	0	0	327	999	999	1,950	1,950
Cost Effectiveness ($/ton MSW)	0	0	2.34	7.14	7.14	13.90	13.90
Facility Down Time (Months)	0	0	1	1	1	1	1
Total Compliance Time (Months)	1	1	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

TABLE 10.1-11. ENERGY IMPACTS FOR THE LARGE MODULAR EXCESS-AIR COMBUSTOR MODEL PLANT CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	125	0
4	448	0
5	448	0
6	2,040[b]	0
7	2,040[b]	0

[a] Increase from baseline consumption.

[b] Excludes the electrical credit of not operating the ESP's.

10.2 SMALL MASS BURN WATERWALL COMBUSTOR

This model plant described in this section represents projected small mass burn plants which will commence construction by November 1989 and will be subject to the Section 111(d) guidelines rather than to the proposed NSPS. This model plant is the same as the one described in Section 5.3 except that baseline for the model includes good combustion practices and temperature control to 450^0F whereas the model plant discussed in Section 5.3 does not. Table 10.2-1 summaries the combustion, temperature, particulate, and acid gas control technologies that were combined for each of the control options described in Section 3.0. As with the model plant described in Section 5.3, the model plant already achieves good PM control at baseline; Option 1 is identical to Option 2.

The environmental performances, costs, and energy impacts for baseline and the control options were adjusted from those presented in Section 5.3 to reflect the change in baseline. A summary of these impacts and costs are presented in the following three sections.

10.2.1 Environmental Performance

Table 10.2-2 summarizes the environmental performances of baseline and each control option. Because of the change in baseline, baseline emissions are equivalent to those presented under Control Option 1 and 2. Furthermore, CDD/CDF emissions for Options 4 and 5 are 75 percent lower than baseline and CDD/CDF emissions for Option 6 and 7 are 98 percent lower than baseline. CO emissions for the control options are equivalent to those of baseline. The respective emission rates and the emission reductions from baseline of other pollutants (PM, SO_2, and HCl) for each control options remain unchanged from those presented in Section 5.3. Similarly, total solid waste disposal rates of the control options also remain unchanged. Because this model plant uses good combustion practices in the baseline whereas the model plant described in Section 5.3 does not, baseline emissions of CDD/CDF and CO in Table 10.2-2 are 93 and 88 percent lower, respectively, than those presented at baseline for the small mass burn waterwall model plant in Section 5.3.

TABLE 10.2-1. SUMMARY OF CONTROL OPTIONS FOR SMALL MASS BURN WATERWALL COMBUSTOR

			Particulate control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion Control							
3. Best PM Control and Combustion and Temperature Control				X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 10.2-2. ENVIRONMENTAL PERFORMANCE SUMMARY FOR SMALL MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS
(Two units of 100 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	200	200	200	200	500	50	12	5
Mg/yr[b]	5.2E-5	5.2E-5	5.2E-5	5.2E-5	1.3E-4	1.3E-5	5.2E-6	1.3E-6
% Reduction vs. Baseline	--	0	0	0	75	75	98	98
CO Emissions								
(ppmv)	50	50	50	50	50	50	50	50
Mg/yr	15	15	15	15	15	15	15	15
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01
Mg/yr	30	30	30	6	6	6	6	6
% Reduction vs. Baseline	--	0	0	20	20	20	20	20
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	146	146	146	146	87	87	14	14
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	212	212	212	212	42	42	6	6
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	60	60	60	60	64	64	65	65
Mg/yr	18,140	18,140	18,140	18,170	19,260	19,260	19,610	19,610
% Increase vs. Baseline	--	0	0	0.1	6	6	8	8

---

[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis.

[b] Mass emission rates are for total plant (both combustors).

10.2.2 Costs

The total capital and annualized costs of each option are presented in Table 10.2-3 for the model plant described in this Section. The costs for the control options that include good combustion practices (Options 2, 3, 5, and 7) were estimated as the difference between the costs presented in Table 5.3-13 and the costs of both the combustor control presented in Tables 5.3-3 and 5.3-4 and of temperature control presented in Tables 5.3-5 and 5.3-6.

Overall, both capital and annualized costs in Table 10.2-3 are higher for higher levels of control. Since good PM control is achieved at baseline, no costs are presented for Options 1 and 2. Costs of Options 4 and 5 are the same as are the costs of Options 6 and 7. Total capital and annualized costs for the most expensive option (Options 6 or 7) are $8,190,000 and $2,570,000, respectively.

10.2.3 Energy Impacts

Table 10.2-4 presents a summary of the energy impacts associated with the control options for the model plant described in this section. The electricity consumed for Options 1 to 7 were estimated from those presented in Table 5.3-14 by subtracting the electricity consumed for temperature control to 450^{0}F (Option 1 in Table 5.3-14). The spray dryer with fabric filter control options consume the most electricity (1,240 MWh/yr). Auxiliary fuel is assumed to be fired during baseline. Thus, no increase in auxiliary fuel use beyond baseline is expected for the control options.

TABLE 10.2-3. COST SUMMARY FOR SMALL MASS BURN WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units at 100 tpd)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	2,050	3,810	3,810	8,190	8,190
Downtime Cost	0	0	235	235	235	235	235
Annualized Capital and Downtime Cost	0	0	300	531	531	1,110	1,110
Direct O&M Cost	0	0	72	498	498	654	654
Total Annual Cost	0	0	483	1,250	1,250	2,190	2,190
Cost Effectiveness ($/ton MSW)	0	0	7.24	18.80	18.80	32.90	32.90
Facility Downtime (Months)	0	0	1	1	1	1	1

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

TABLE 10.2-4 ENERGY IMPACTS FOR SMALL MASS BURN WATERWALL COMBUSTOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	92	0
4	600	0
5	600	0
6	1,420[b]	0
7	1,420[b]	0

[a] Increase from baseline consumption.

[b] Total electrical use excludes the electrical savings of not operating the existing ESP's.

10.3 LARGE RDF-FIRED COMBUSTOR

The model plant described in this section represents projected large RDF-fired plants which will commence construction by November 1989 and will be subject to the Section 111(d) guidelines rather than to the proposed NSPS. The model plant is the same as the one described in Section 6.1 except that baseline for the model includes good combustion practices and temperature control to 450°F whereas the model plant discussed in Section 6.1 does not. It is assumed that the downtime associated with retrofitting APCD's for control options will take only 1 month per combustor. This downtime period for this model plant is shorter than those assumed for the model plant described in Section 6.1. In addition, access and congestion for retrofitting APCD's are assumed to be moderate for this model plant. A high access and congestion factor was assumed for the model plant in Section 6.1. Table 10.3-1 summarizes the combustion, temperature, particulate, and acid gas control technologies that were combined for each of the control options described in Section 3.0. As with the model plant described in Section 6.1, the model plant already achieves best PM control at baseline; Option 1 to 3 are identical.

The environmental performances, costs, and energy impacts for baseline and the control options were adjusted for those presented in Section 6.1 to reflect the changes in baseline, downtime, and access/congestion. A summary of these impacts and costs are presented in the following three sections.

10.3.1 Environmental Performance

Table 10.3-2 summarizes the environmental performances of baseline and each control option. Because of the changes in baseline, baseline emissions are equivalent to those presented under Control Options 1 to 3. Furthermore, CDD/CDF emissions for Options 4 and 5 are 75 percent lower than those of baseline, and CDD/CDF emissions for Option 6 and 7 are 99 percent lower than baseline. CO emissions for the control options are equivalent to those of baseline. The respective emission rates and emission reductions from baseline of the other pollutants (PM, SO_2, and HCl) remains unchanged from those presented in Section 6.1. Similarly, total solid waste disposal rates of the control options also remain unchanged. Because the model plant

TABLE 10.3-1 SUMMARY OF CONTROL OPTIONS FOR LARGE RDF-FIRED MWC MODEL PLANT

Control Option Description	Combustion Modifications	Temperature Control	Particulate control		Acid Gas Control		
			Existing ESP Rebuilt	Additional SCA	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion Control							
3. Best PM Control and Combustion and Temperature Control							
4. Good Acid Gas Control, Best PM Control and Temperature Control		X				X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X				X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 10.3-2 ENVIRONMENTAL PERFORMANCE SUMMARY FOR LARGE RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a,b] (Two units of 1,000 tpd RDF each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	1000	1000	1000	1000	250	250	10	10
Mg/yr[b]	3.2E-3	3.2E-3	3.2E-3	3.2E-3	8.0E-4	8.0E-4	3.2E-5	3.2E-5
% Reduction vs. Baseline	--	0	0	0	75	75	99	99
CO Emissions								
(ppmv)	150	150	150	150	150	150	150	150
Mg/yr	554	554	554	554	554	554	554	554
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	73	73	73	73	73	73	73	73
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
SO_2 Emissions								
(ppmv)	300	300	300	300	180	180	29	29
Mg/yr	2,420	2,420	2,420	2,420	1,450	1,450	230	230
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	2,430	2,430	2,430	2,430	485	485	73	73
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	200	200	200	200	249	249	265	265
Mg/yr	60,500	60,500	60,500	60,500	75,400	75,400	80,400	80,400
% Increase vs. Baseline	--	0	0	0	25	25	33	33

[a] All flue gas concentrations are reported on a 7 percent O_2 dry basis.

[b] Mass emission rates are for total plant (both combustors).

uses good combustion practices whereas the model plant described in Section 6.1 does not, baseline emissions of CDD/CDF and CO in Table 10.3-2 are 87 and 25 percent lower, respectively, than those presented at baseline for the large RDF-fired model plant in Section 6.1.

10.3.2 Costs

The total capital and annualized costs for each options are presented in Table 10.3-3 for the model plant described in this section. The costs for the control options that include good combustion practices (Options 2, 3, 5 and 7) were estimated as the difference between the costs presented in Table 6.1-11 and the costs of the combustor control presented in Tables 6.1-3 and 6.1-4. Total capital costs presented in Table 10.3-3 for moderate access and congestion were estimated from those presented in Section 6.1 for high access and congestion. Direct capital costs for the model plant were estimated by multiplying the direct capital costs presented in Section 6.1 an the ratio of the access and congestion factors. Indirect and contingency costs were calculated from the direct capital costs using appropriate multipliers. Similarly, downtime costs presented in Table 10.3-3 for one month were prorated from those presented in Table 6.1-11 based on facility downtimes.

Overall, both capital and annualized costs in Table 10.3-3 are higher for higher levels for control. Since best PM control is achieved at baseline, no costs are presented for Options 1 to 3. Costs of Options 4 and 5 are the same as well as the costs of Options 6 and 7. Total capital and annualized costs for the most expensive option (Options 6 or 7) are $26,200,000 and $9,170,000, respectively.

10.3.3 Energy Impacts

Table 10.3-4 presents a summary of the energy impacts associated with the control options for the model plant described in this section. The spray dryer with fabric filter control options consume the most electricity (7,710 MWh/yr). No increase in auxiliary fuel use beyond baseline is expected for the control options.

TABLE 10.3-3 COST SUMMARY FOR LARGE RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a] (Two units of 1,000 tpd RDF each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	0	2,240	2,240	26,200	26,200
Downtime Cost	0	0	0	3,260	3,260	3,260	3,260
Annualized Capital and Downtime Cost	0	0	0	724	724	3,870	3,870
Direct O&M Cost	0	0	0	1,790	1,790	2,980	2,980
Total Annual Cost	0	0	0	2,640	2,640	8,170	8,170
Cost Effectiveness ($/ton RFD)	0	0	0	4.00	4.00	12.26	12.26
Facility Downtime (Months)	0	0	0	1	1	1	1
Total Compliance Time (Months)	1	1	1	19	19	25	25

---

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars and based on moderate access/congestion.

TABLE 10.3-4. PLANT TOTAL ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	0	0
4	615	0
5	615	0
6	13,300[b]	0
7	13,300[b]	0

[a] Increase from baseline consumption.

[b] Total electrical use excludes the electrical savings of not operating the existing ESP's.

10.4 SMALL RDF-FIRED COMBUSTOR

The model plant described in this section represents projected small RDF-fired plants which will commence construction by November 1989 and will be subject to the Section 111(d) guidelines rather than to the proposed NSPS. The model plant is the same as the one described in Section 6.2 except that baseline for the model includes good combustion practices whereas the model plant discussed in Section 6.2 does not. It is assumed that the downtime associated with retrofitting APCD's for control options will taken only 1 month per combustor. This downtime period for this model plant is shorter than those assumed for the model plant described in Section 6.2. In addition, access and congestion for retrofitting APCD's are assumed to be moderate for this model plant. A high access and congestion factor was assumed for the model plant in Section 6.2. Table 10.4-1 summarizes the combustion, temperature, particulate, and acid gas control technologies that were combined for each of the control options described in Section 3.0. As with the model plant described in Section 6.2, the model plant already achieves best PM control at baseline; Options 1 to 3 are identical.

The environmental performances, costs, and energy impacts for baseline and the control options were adjusted for those presented in Section 6.2 to reflect the changes in baseline, downtime, and access/congestion. A summary of these impacts and costs are presented in the following three sections.

10.4.1 Environmental Performance

Table 10.4-2 summarizes the environmental performances of baseline and each control option. Because of the change in baseline, baseline emissions are equivalent to those presented under Control Options 1 to 3. Furthermore, CDD/CDF emissions for Options 4 and 5 are 75 percent lower than those of baseline, and CDD/CDF emissions for Options 6 and 7 are 99 percent lower than baseline. CO emissions for the control options are equivalent to those of baseline. The respective emission rates and emission reductions from baseline of the other pollutants (PM, SO_2, and HCl) remains unchanged from those presented in Section 6.2. Similarly, total solid waste disposal rates of the control options also remain unchanged. Because the model plant uses good combustion practices whereas the model plant described in

TABLE 10.4-1 SUMMARY OF CONTROL OPTIONS FOR SMALL RDF-FIRED MWC MODEL PLANT

			Particulate control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion and Temperature Control							
3. Best PM Control and Combustion and Temperature Control							
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 10.4-2 ENVIRONMENTAL PERFORMANCE SUMMARY FOR SMALL RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)[b]	1000	1000	1000	1000	250	250	10	10
Mg/yr	9.6E-4	9.6E-4	9.6E-4	9.6E-4	2.4E-4	2.4E-4	9.6E-6	9.6E-6
% Reduction vs. Baseline	--	0	0	0	75	75	99	99
CO Emissions								
(ppmv)	100	100	100	100	100	100	100	100
Mg/yr	119	119	119	119	119	119	119	119
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Mg/yr	22	22	22	22	22	22	22	22
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
SO_2 Emissions								
(ppmv)	300	300	300	300	180	180	29	29
Mg/yr	819	819	819	819	491	491	78	78
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	778	778	778	778	156	156	22	22
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	60	60	60	60	75	75	80	80
Mg/yr	18,200	18,200	18,200	18,200	22,700	22,700	24,100	24,100
% Increase vs. Baseline	--	0	0	0	25	25	33	33

[a] All flue gas concentrations are reported on a 7 percent O_2 dry basis. Standard and normal conditions are both 1 atmosphere and 70°F.

Section 6.1 does not, baseline emissions of CDD/CDF and CO in Table 10.4-2 are 80 and 71 percent lower, respectively, than those presented at baseline for the small RDF-fired model plant in Section 6.2.

10.4.2 Costs.

The total capital and annualized costs of each options are presented in Table 10.4-3 for the model plant described in this section. The costs for the control options that include good combustion practices (Options 2, 3, 5, and 7) were estimated as the difference between the costs presented in Table 6.2-11 and the costs of the combustor control presented in Tables 6.2-3 and 6.2-4. Total capital costs presented in Table 10.4-3 for moderate access and congestion were estimated from those presented in Section 6.2 for high access and congestion. Direct capital costs for the model plant were estimated by multiplying the direct capital costs presented in Section 6.2 and the ratio of the access and congestion factors. Indirect and contingency costs were estimated from the direct capital costs appropriate multipliers. Similarly, downtime costs presented in Table 10.3-3 for one month were prorated from those presented in Table 6.2-11 based on facility downtimes.

Overall, both capital and annualized costs in Table 10.4-3 are higher for higher levels of control. Since best PM control is achieved at baseline, no costs are presented for Options 1 to 3. Costs of Options 4 and 5 are the same as well as the costs of Options 6 and 7. Total capital and annualized costs for the most expensive option (Options 6 or 7) are $14,100,000 and $4,700,000, respectively.

10.4.3 Energy Impacts

Table 10.4-4 presents a summary of the energy impacts associated with the control options for the model plant described in this section. The spray dryer with fabric filter control options consume the most electricity (3,060 MWh/yr). No increase in auxiliary fuel use beyond baseline is expected for the control options. The incremental electrical and auxiliary fuel consumptions from baseline in Table 10.4-4 are the same as those for the model plant in Section 6.2.

TABLE 10.4-3 COST SUMMARY FOR SMALL RDF-FIRED MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 300 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	0	5,060	5,110	14,100	14,100
Downtime Cost	0	0	0	978	978	978	978
Annualized Capital and Downtime Cost	0	0	0	801	801	1,990	1,990
Direct O&M Cost	0	0	0	840	840	1,240	1,240
Total Annual Cost	0	0	0	1,930	1,930	3,950	3,950
Cost Effectiveness ($/ton RDF)	0	0	0	9.65	9.65	19.80	19.80
Facility Downtime (Months)	0	0	0	1	1	1	1
Total Compliance Time (Months)	1	1	1	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs are in December 1987 dollars and are based on moderate access and congestion.

TABLE 10.4-4. PLANT TOTAL ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	0	0
4	615	0
5	615	0
6	4,150[b]	0
7	4,150[b]	0

[a] Incremenatal use from baseline.

[b] Excludes the electrical credit of not operating the ESP's.

10.5 ROTARY WATERWALL COMBUSTOR

The model plant described in this section represents projected rotary waterwall plants which will commence construction by November 1989 and will be subject to the Section 111(d) guidelines rather than to the proposed NSPS. The model plant is the same as the one described in Section 9.1 except that baseline for the model includes good combustion practices whereas the model plant discussed in Section 9.1 does not. Table 10.5-1 summarizes the combustion, temperature, particulate, and acid gas control technologies that were combined for each of the control options described in Section 3.0. As with the model plant described in Section 9.1, the model plant already achieves good PM control at baseline; Option 1 and 2 are identical.

The environmental performances, costs, and energy impacts for baseline and the control options were adjusted for those presented in Section 9.1 to reflect the changes in baseline. A summary of these impacts and costs are presented in the following three sections.

10.5.1 Environmental Performance

Table 10.5-2 summarizes the environmental performances of baseline and each control option. Because of the changes in baseline, baseline emissions are equivalent to those presented under Control Options 1 to 2. Furthermore, CDD/CDF emissions for Options 4 and 5 are 75 present lower than those of baseline, and CDD/CDF emissions for Option 6 and 7 are 99 percent lower than baseline. CO emissions for the control options are equivalent to those of baseline. The respective emission rates and emission reductions from baseline of the other pollutants (PM, SO_2, and HCl) remains unchanged from those presented in Section 9.1. Similarly, total solid waste disposal rates of the control options also remain unchanged. Because the model plant uses good combustion practices whereas the model plant described in Section 6.1 does not, baseline emissions of CDD/CDF in Table 10.5-2 are 80 percent lower than those presented at baseline for the rotary waterwall model plant in Section 9.1.

10.5.2 Costs

The total capital and annualized costs for each options are presented in Table 10.5-3 for the model plant described in this section. The costs for the control options that include good combustion practices (Options 2,

TABLE 10.5-1 SUMMARY OF CONTROL OPTIONS FOR ROTARY WATERWALL COMBUSTOR

			Particulate Control		Acid Gas Control		
Control Option Description	Combustion Modifications	Temperature Control	Existing ESP Rebuilt	Additional Plate Area	New Fabric Filter	Sorbent Injection	Spray Dryer
1. Good Combustion and Temperature Control							
2. Good PM Control with Combustion Control and Temperature Control							
3. Best PM Control and Combustion and Temperature Control				X			
4. Good Acid Gas Control, Best PM Control and Temperature Control		X		X		X	
5. Good Acid Gas Control and Best PM/Combustion/ Temperature Control		X		X		X	
6. Best Acid Gas Control, Best PM Control, and Temperature Control		X			X		X
7. Best Acid Gas Control and Best PM/Combustion/ Temperature Control		X			X		X

TABLE 10.5-2 ENVIRONMENTAL PERFORMANCE SUMMARY FOR ROTARY WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 250 tpd each)

	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total CDD/CDF Emissions								
(ng/dscm)	400	400	400	400	100	100	5	5
Mg/yr	2.6E-4	2.6E-4	2.6E-4	2.6E-4	6.5E-5	6.5E-5	3.2E-6	3.2E-6
% Reduction vs. Baseline	--	0	0	0	75	75	99	99
CO Emissions								
(ppmv)	100	100	100	100	100	100	100	100
Mg/yr	81	81	81	81	81	81	81	81
% Reduction vs. Baseline	--	0	0	0	0	0	0	0
PM Emissions								
(gr/dscf)	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01
Mg/yr	49	49	49	16	16	16	16	16
% Reduction vs. Baseline	--	0	0	67	67	67	67	67
SO_2 Emissions								
(ppmv)	200	200	200	200	120	120	19	19
Mg/yr	370	370	370	370	222	222	35	35
% Reduction vs. Baseline	--	0	0	0	40	40	90.5	90.5
HCl Emissions								
(ppmv)	500	500	500	500	100	100	15	15
Mg/yr	528	528	528	528	106	106	15	15
% Reduction vs. Baseline	--	0	0	0	80	80	97	97
Total Solid Waste								
(tons/day)	150	150	150	150	159	159	162	162
Mg/yr	45,500	45,500	45,500	45,500	48,500	48,500	48,970	48,970
% Increase vs. Baseline	--	0	0	0	7	7	8	8

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[a] All flue gas concentrations are reported on a dry 7 percent O_2 basis. Normal and standard conditions are 1 atmosphere and 70°F.

TABLE 10.5-3 COST SUMMARY FOR ROTARY WATERWALL MWC MODEL PLANT RETROFIT CONTROL OPTIONS[a]
(Two units of 250 tpd each)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total Capital Cost	0	0	1,990	4,140	4,140	10,600	10,600
Downtown Cost	0	0	588	588	588	588	588
Annualized Capital and Downtime Cost	0	0	339	622	622	1,470	1,470
Direct O&M Cost	0	0	26	642	642	913	913
Total Annual Cost	0	0	457	1,500	1,550	2,960	2,960
Cost Effectiveness ($/ton MSW)	0	0	2.74	9.00	9.30	17.80	17.80
Facility Downtime (Months)	0	0	1	1	1	1	1
Total Compliance Time (Months)	1	1	19	19	19	25	25

[a] All costs (except cost effectiveness) given in $1000. All costs in December 1987 dollars.

3, 5 and 7) were estimated as the difference between the costs presented in Tables 9.1-14 and the costs of the combustor presented in Table 9.1-4 and 9.1-5.

Overall, both capital and annualized costs in Table 10.5-3 are higher for higher levels for control. Since good PM control is achieved at baseline, no costs are presented for Options 1 and 2. Costs of Options 4 and 5 are the same as well as the costs of Options 6 and 7. Total capital and annualized costs for the most expensive option (Options 6 or 7) are $10,600,000 and $3,490,000, respectively.

10.5.3 Energy Impacts

Table 10.5-4 presents a summary of the energy impacts associated with the control options for the model plant described in this section. The spray dryer with fabric filter control options consume the most electricity (2,050 MWh/yr). No increase in auxiliary fuel use beyond baseline is expected for the control options. The incremental electrical and auxiliary fuel consumptions from baseline in Table 10.5-4 are the same as those for the model plant in Section 9.1.

TABLE 10.5-4. PLANT TOTAL ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	102	0
4	672	0
5	672	0
6	2,520[b]	0
7	2,520[b]	0

[a] Increase from baseline consumption.

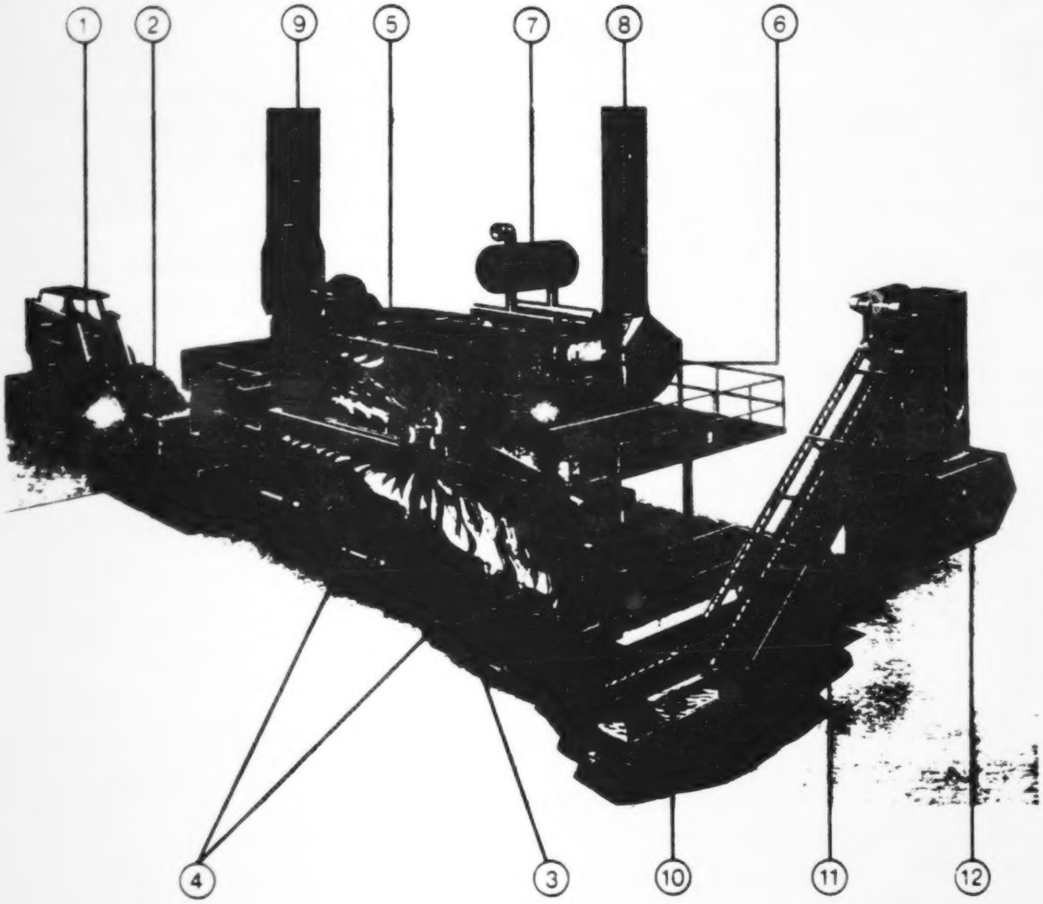
[b] Excludes the electrical credit of not operating the ESP's.

TABLE 10.5-4. PLANT TOTAL ENERGY IMPACTS FOR CONTROL OPTIONS[a]

Option	Electrical Use (MWh/yr)	Gas Use (Btu/yr)
1	0	0
2	0	0
3	102	0
4	672	0
5	672	0
6	2,520[b]	0
7	2,520[b]	0

[a] Increase from baseline consumption.

[b] Excludes the electrical credit of not operating the ESP's.



The above cutaway view of the standard CONSUMAT' energy-from-waste module shows how material and hot gas flows are controlled to provide steam from solid waste. A skid steer tractor (1) pushes the waste to the automatic loader (2). The loader then automatically injects the waste into the gas production chamber (3) where transfer rams (4) move the material slowly through the system. The high temperature environment in the gas production chamber is provided with a controlled quantity of air so that gases from the process are not burned in this chamber but fed to the upper or pollution control chamber (5). Here the gases are mixed with air and controlled to maintain a proper air fuel ratio and temperature for entrance into the heat exchanger (6) where steam is produced. A steam separator (7) is provided to ensure high quality steam. In normal operation gases are discharged through the energy stack (8). When steam is not required or in the event of a power failure. hot gases are vented through the dump stack (9). The inert material from the combustion process is ejected from the machine in the form of ash into the wet sump (10) and conveyed (11) into a closed bottom container (12) which can then be hauled to the landfill for final disposal.

Figure 7.1-1. Typical Consumat Module

TABLE 7.1-1. TUSCALOOSA, ALABAMA DESIGN DATA

Combustor:	
Type	- Modular Starved air
Number of Combustors	- 4 Consumat #CS=3000
Combustor Unit Capacity	- 75 tpd (each)
Total Plant Capacity	- 300 tpd
Number of Boilers	- 2 Richmond Engineering Waste Heat Boilers
Boiler Design Rate	- 32,000 lb/hr steam (each)
Emission Controls:	
Type	- Electrostatic Precipitator
Number of Precipitators	- 1
Number of Fields	- 2
Inlet design particulate loading	- 0.10 gr/dscf at 12% CO_2
Operating Temperature	- 450°F
Design Collection Efficiency	- 50 percent
Particulate Emission Limit	- 0.08 gr/dscf at 12% CO_2
Gas Flow	- 90,000 acfm